8-AM

FLOW CHARACTERISTICS OF COMMERCIALLY AVAILABLE DRILLING CHOKES USED IN WELL CONTROL OPERATIONS

A Thesis

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by
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One of the more expensive and potentially dangerous problems confronting the oil producing industry is the control of high pressure formation fluids encountered while drilling for hydrocarbon reservoirs. When thses formation fluids enter the wellbore, a well control procedure must be employed which allows the formation fluid intrusion to be removed and the drilling fluid density to be increased sufficiently to overcome the formation pressure. This is accomplished by circulating the well under pressure through the use of a drilling choke.

The efficient manipulation of the drilling choke remains to be one of the most difficult of well control procedures. A mathematical model of the choke behavior is needed to allow simulation of the well control operation for training and research purposes. This model should be capable of relating choke position, rate of flow, and pressure drop across the choke for drilling fluids of varing rheological properties. It is felt that the best approach for developing the needed mathematical model is through empirical correlations based on experimental observations.

In this study, a series of experiments were conducted to determine the flow characteristics of four commercially available drilling chokes used in well control operations. Pressure drops across the drilling chokes were measured for various choke positions, flow rates, and fluid properties. Both newtonian and non-newtonian fluids were used, covering a wide range of rheological properties. The fluid densities investigated ranged from 8.33 pounds per gallon to 12.05 pounds per gallon, with specific gravities from 1.00 to 1.45. A series of curves relates the experimentally obtained pressure drop-flow rate data of the drilling choke to the respective choke positions. From these curves valve coefficients are calculated. Plots relating these valve coefficients to their respective choke positions for the various fluids are developed for each choke.

It is shown that flow through the drilling choke is almost unrestricted until the choke is approximately fifty percent closed. Futhermore, the effects of viscosity are minor when considering single phase, incompressible flow of common drilling fluids through drilling chokes.

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LIST OF TABLES

LIST OF FIGURES

ABSTRACT

One of the more expensive and potentially dangerous problems confronting the oil producing industry is the control of high pressure formation fluids encountered while drilling for hydrocarbon reservoirs. When these formation fluids enter the wellbore, a well control procedure must be employed which allows the formation fluid intrusion to be removed and the drilling fluid density to be increased sufficiently to overcome the formation pressure. This is accomplished by circulating the well under pressure through the use of a drilling choke.

The efficient manipulation of the drilling choke remains to be one of the most difficult of well control procedures. A mathematical model of the choke behavior is needed to allow simulation of the well control operation for training and research purposes. This model should be capable of relating choke position, rate of flow, and pressure drop across the choke for drilling fluids of varying rheological properties. It is felt that the best approach for developing the needed mathematical model is through empirical correlations based on experimental observations.

In this study, a series of experiments were conducted to determine the flow characteristics of four

commercially available drilling chokes used in well control operations. Pressure drops across the drilling chokes were measured for various choke positions, flow rates, and fluid properties. Both Newtonian and non-Newtonian fluids were used, covering a wide range of rheological properties. The fluid densities investigated ranged from 8.33 pounds per gallon to 12.05 pounds per gallon, with specific gravities from 1.00 to 1.45. A series of curves relates the experimentally obtained pressure drop-flow rate data of the drilling choke to the respective choke positions. From these curves valve coefficients are calculated. Plots relating these valve coefficients to their respective choke positions for the various fluids are developed for each choke.

It is shown that flow through the drilling choke is almost unrestricted until the choke is approximately fifty percent closed. Furthermore, the effects of viscosity are minor when considering single phase, incompressible flow of common drilling fluids through drilling chokes.

CHAPTER I

INTRODUCTION

Control of the flow of high pressure formation fluids into the wellbore is not an uncommon problem confronting the petroleum industry. However, the potential danger to rig personnel and the potential cost in terms of equipment, ecology, and lost hydrocarbon production warrant the proper instruction of industry personnel in well control procedures. Incorrect handling of a kick may well result in a blowout, i.e. the uncontrolled flow of formation fluids from the well.

When these fluids flow from one subsurface formation, usually the most recently penetrated zone, to a hydrofracture in a second subsurface formation, an underground blowout has occurred. Due to its confinement to a subsurface formation, an underground blowout is not as immediately dangerous as a surface blowout. However, an underground blowout is quite difficult to control since both formation fluids and drilling fluids are "lost" to the fractured formation. In many cases, the lower portion of the well must be sealed off, and a new well drilled, causing expenses to soar.

Of particular danger to both man and environment is the surface blowout. This occurs as high pressure formation fluids work their way vertically to the surface or sea floor. Destruction of expensive rig equipment and considerable damage to the environment are inevitable, but still secondary, to the extreme danger of injury or death to drilling personnel. In some cases, costly relief wells must be drilled in an attempt to flood the high pressure stratum causing the flow.

Blowouts are sometimes the result of equipment failure, but they are also caused by human error. The failure of drilling personnel to recognize the warning signs of a kick and react accordingly is a significant factor in many blowouts, and is the principal reason behind the tremendous amounts of time and effort invested by the petroleum industry in training of personnel.

The Department of Petroleum Engineering at Louisiana State University has played an active role over the past seven years in the training of industry personnel in present day methods of well control. Through the use of well control simulators and the two training wells owned and operated by LSU, modern techniques of well control for both onshore and offshore operations are taught to drilling personnel. The training wells lend themselves not only to evaluations of present day methods of well control, but also to research and development of new methods.

Within the industry, in-depth studies of well control procedures and blowout prevention have led to:

1) Improved techniques for abnormal pressure prediction.
2) Improved well control equipment.
3) Improved procedures for circulating out kicks and killing wells under various conditions.

For some time it was common practice to use the "constant pit level method" for circulating out formation fluid intrusions, commonly referred to as "kicks". This method involves maintaining the rate of flow from the pump into the well equal to the rate of flow out of the well. The drawback to this method lies in the fact that the kick fluids are not allowed to expand as they travel up the wellbore. In the case of a gas kick, the pressure of the kick is equal to that of the initial bottom hole pressure. Therefore, as the kick nears the surface, the casing seat, adjacent formations, and the blowout preventer are all subject to high and possibly excessive pressures. Should the surface equipment fail, the result will be a surface blowout. If the pressures are, indeed, excessive, and the blowout preventers hold, a fracture at the casing seat or in adjacent formations will develop into an underground blowout.

O'Brien and Goins[1] proposed the "constant bottom hold pressure" method, the technique for circulating out kicks which has gained universal acceptance today. This procedure requires that one maintain a constant bottom hole pressure equal to or slightly greater than the formation pressure. This is accomplished through the use of a drilling choke which, when manipulated properly, will exert enough back pressure to prevent the flow of kick fluids into the wellbore. An additional advantage of the constant bottom hole pressure method is that the kick fluid is allowed to expand, thus reducing the pressures exerted on the casing seat and adjacent formations as these fluids are circulated up the annulus.

When a kick is detected, the well is immediately shut in so that the volume of formation fluids entering the wellbore can be minimized. Having shut-in the well, the drill pipe pressure will show the difference between the formation pressure and the hydrostatic pressure of the column of drilling fluid in the well. Since the hydrostatic pressure must be equal to or slightly greater than the formation pressure to prevent the flow of formation fluids into the wellbore, the drilling fluid density must be increased to overcome the formation pressure.

To remove from the wellbore all formation fluids and to replace the former drilling fluid with the higher density drilling fluid, the drilling choke is opened simultaneously to the pumping of new drilling fluid into the string. The drilling choke must be adjusted accurately so that the casing pressure remains constant as the pump is brought to the proper speed. By holding the casing pressure constant, the bottom hole pressure is likewise held constant. The choke operator must correctly manipulate the choke, for too much casing pressure will surely fracture the lighter formations, whereas too little casing pressure will allow formation fluids to flow into the wellbore.

Once the desired or reduced pump speed has been obtained, the choke operator is required to follow a drill pipe pressure schedule. Paying close attention to the stroke counter and drill pipe pressure gauge he must adjust the choke so that the drill pipe pressure on the gauge conforms to that on the schedule for the number of strokes pumped. The initial circulating drill pipe pressure (at zero strokes pumped) is the sum of the pump pressure at the reduced pump speed and the shut-in drill pipe pressure. The final circulating drill pipe pressure is obtained when the new drilling fluid or new mud has been pumped to the bit. This pressure is equal to the ratio of the weight of the new mud to that of the former drilling fluid or old mud, multiplied by the pump pressure at the reduced pump speed. Not only must the choke operator insure this pressure to be the drill pipe pressure when surface-to-bit strokes has been pumped, but he must also maintain this pressure until new mud has been completely circulated through the well, and is now the only fluid in the wellbore. The drill pipe pressure schedule is of great assistance to the choke operator in that it allows him to follow a table relating drill pipe pressure to strokes pumped as the drill pipe pressure is dropped from the initial to the final valve.

One of the more critical well control operations during which proper manipulation of the choke is absolutely mandatory involves choke operation as the kick reaches the surface. If the most severe case is considered, that of drilling in deep water and taking a gas kick, one may be able to understand the requirements placed upon the choke operator.

As the kick nears the sea floor, the choke operator has been following the drill pipe pressure schedule, manipulating the choke as needed. When the gas kick reaches the sea floor, it quickly displaces the mud in the choke line from the sea floor to the rig. This rapid displacement is primarily due to:

1) The choke line capacity is much smaller than that of the annulus
2) The expansion of gas.

When the choke line is displaced with gas, a large amount of hydrostatic pressure is lost, and the drill pipe pressure will drop significantly.

Consider drilling in two thousand feet of water. If a twelve pound per gallon drilling fluid was used initially, the pressure lost would be:

$$p = 0.052\rho D = 1248 \text{ psi}$$

where ρ = fluid density, ppg

D = length of fluid column, ft

p = pressure at bottom of fluid column, psi

The choke operator must quickly adjust the choke until the proper drill pipe pressure is obtained. Some concern in the industry has been expressed about the difficulty of preventing the flow of additional fluid from the formation into the wellbore when gas reaches the seafloor. As second and third kicks are taken, expensive rig time required to circulate these kicks out of the well increases dramatically, not to mention the danger of losing the well.

As the gas is being pumped from the well, the drilling mud will begin to enter the choke line. Again, due to the smaller capacity of the choke line, the mud will rapidly fill the choke line, adding hydrostatic pressure to the well. The amount of pressure previously lost is now gained, and the choke operator must immediately open the choke until the correct drill pipe pressure is once again obtained.

Figure 1.1 displays the approximate response

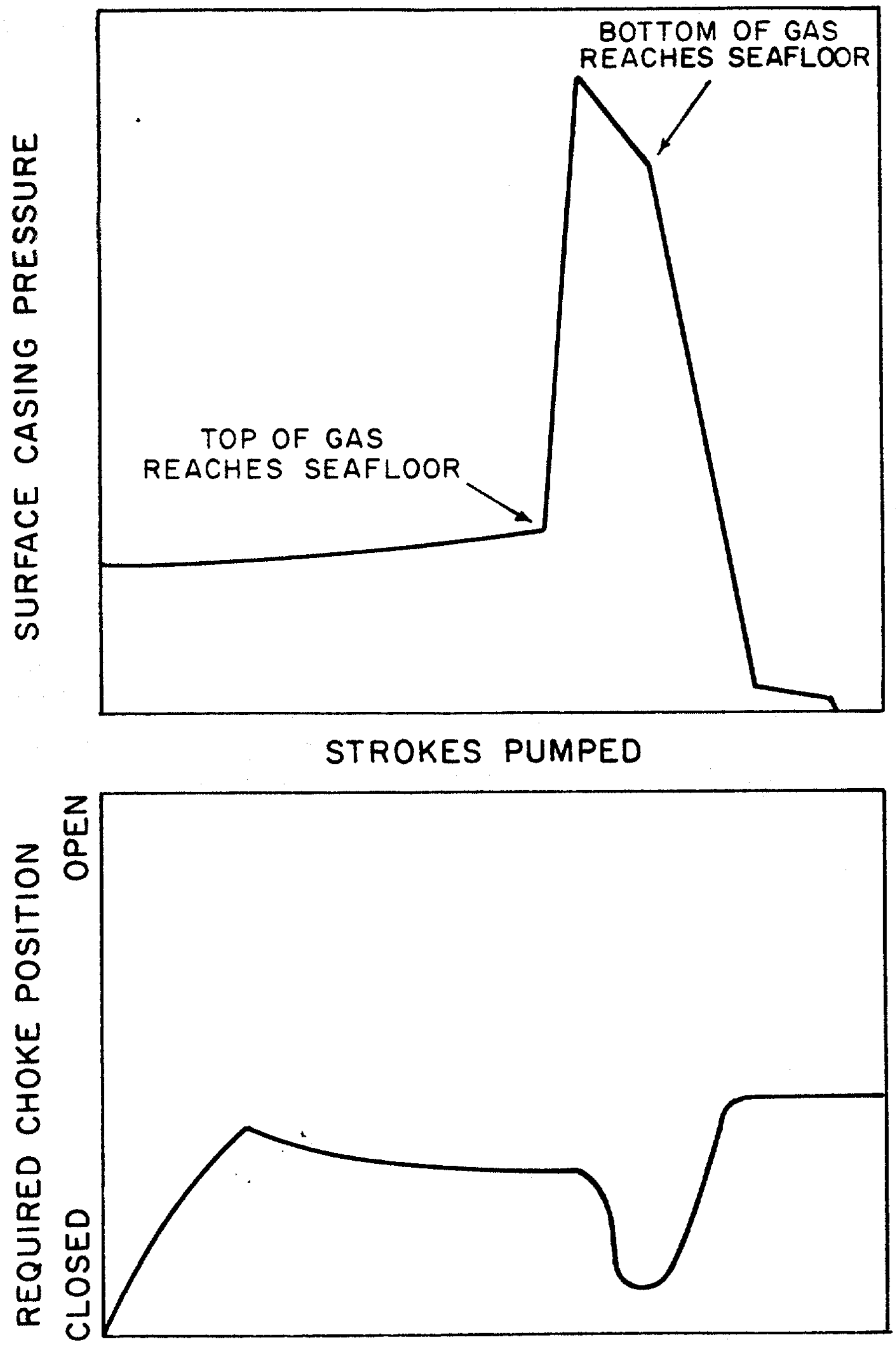


Figure 1.1 - Comparison of Surface Casing Pressure and Required Choke Position For Total Strokes Pumped

required of the choke operator. To better prepare industry personnel, electronic simulators of the well control process are often used. An improved mathematical model of the choke and its behavior is needed to allow a more realistic electronic simulator to be developed. This model should be capable of predicting pressure drop across the choke for various flow rates and changing fluid properties. Under well control operations, flow can be compressible or incompressible. Flow may also be single phase, two, or even three-phase, and thus experimental data is required for each situation for complete development of the model.

This study represents an initial endeavor into the development of such a model. It is an examination of the pressure losses encountered during steady-state flow through four of the commercially available drilling chokes used in well control operations. Fluids of various properties were tested to determine the effects of viscosity and of density on pressure drop for different choke positions. These observations will be coupled with other phases of the overall well control research project so that a mathematical model can be developed.

CHAPTER II

LITERATURE REVIEW

A very common occurrence in the Petroleum and Natural Gas Industry is the flow of fluids through restrictions. Orifice meters, chokes, valves, and swages are just a few of the many different types of equipment present in the flow conduits used by the industry. Calculation techniques are available for describing single and multi-phase flow through restrictions, but they appear inadequate for predicting pressure and flow rate behavior in drilling chokes, especially when non-Newtonian fluids are considered.

This study will be primarily concerned with single-phase, incompressible flow, although single-phase, compressible and multi-phase flow criteria will be introduced. One must remain aware that each calculation technique is limited not only by the fluids used and evaluated, but also by the type and geometric configuration of the restriction through which these fluids pass.

A thorough review of available calculation techniques is necessary because the electronic simulators currently in use employ one or more of these techniques to simulate operation of the choke. An example of this will be discussed at the end of the chapter.

Finally, it should be noted that the term "bean size" refers to the diameter in sixty-fourths of an inch of the equivalent circular area open to flow.

2.1 Single-Phase, Incompressible Flow

Single-phase subcritical flow of gases and liquids is based on a combination of Bernoulli's equation with the equation of continuity.[2] Bernoulli's equation can be written:

$$\frac{v_1^2}{2g} + \frac{p_1 g_c}{\rho_1 g} + z_1 = \frac{v_o^2}{2g} + \frac{p_o g_c}{\rho_o g} + z_o \qquad (2.1)$$

where V = velocity, ft/sec

p = pressure, psi

z = elevation, ft

ρ = density lbm/ft^3

g = gravitational acceleration, ft/sec^2

$$g_c = 32.2 \frac{lb_f\text{-}sec^2}{lb_m - ft}$$

The equation of continuity is:

$$\rho_1 A_1 v_1 = \rho_2 A_2 v_2 \qquad (2.2)$$

where A = area open to flow, ft^2

Combining these two equations, and assuming incompressible horizontal flow, it can be shown that:[3]

$$q = A_o v_o = \frac{C_D}{\sqrt{1 - \left(\frac{A_o}{A_1}\right)^2}} \cdot A_o \sqrt{\frac{2g_c \Delta p}{\rho}} \tag{2.3}$$

where the quantity $\frac{1}{1-(A_o/A_1)^2}$ is called the velocity of approach factor, and C_D is the discharge coefficient.

Then,

$$q = CA_o \sqrt{\frac{2g_c \Delta p (144)}{\rho}} \tag{2.4}$$

where q = ft^3/sec

A_o = cross-sectional area of the choke, ft^2

C = flow coefficient, dimensionless

Δp = pressure drop across choke, psi

ρ = fluid density, lbm/ft^3

Values for C for both nozzles and orifices are obtained using Figure 2-1.[4] C is plotted for Reynolds numbers based on the internal diameter, d_2, of the upstream pipe. If the diameter, d_1, of the nozzle or orifice is known, the ratio, β, of the diameters can be computed, as can the area of the opening, A_o. The flow rate, q, may then be calculated.

For most conditions of flow of fluids having a low viscosity, such as water or gasoline, it is not necesarry to compute Reynold's numbers since the flow coefficient will fall in the range of constant values, as seen in Figure 2-1.

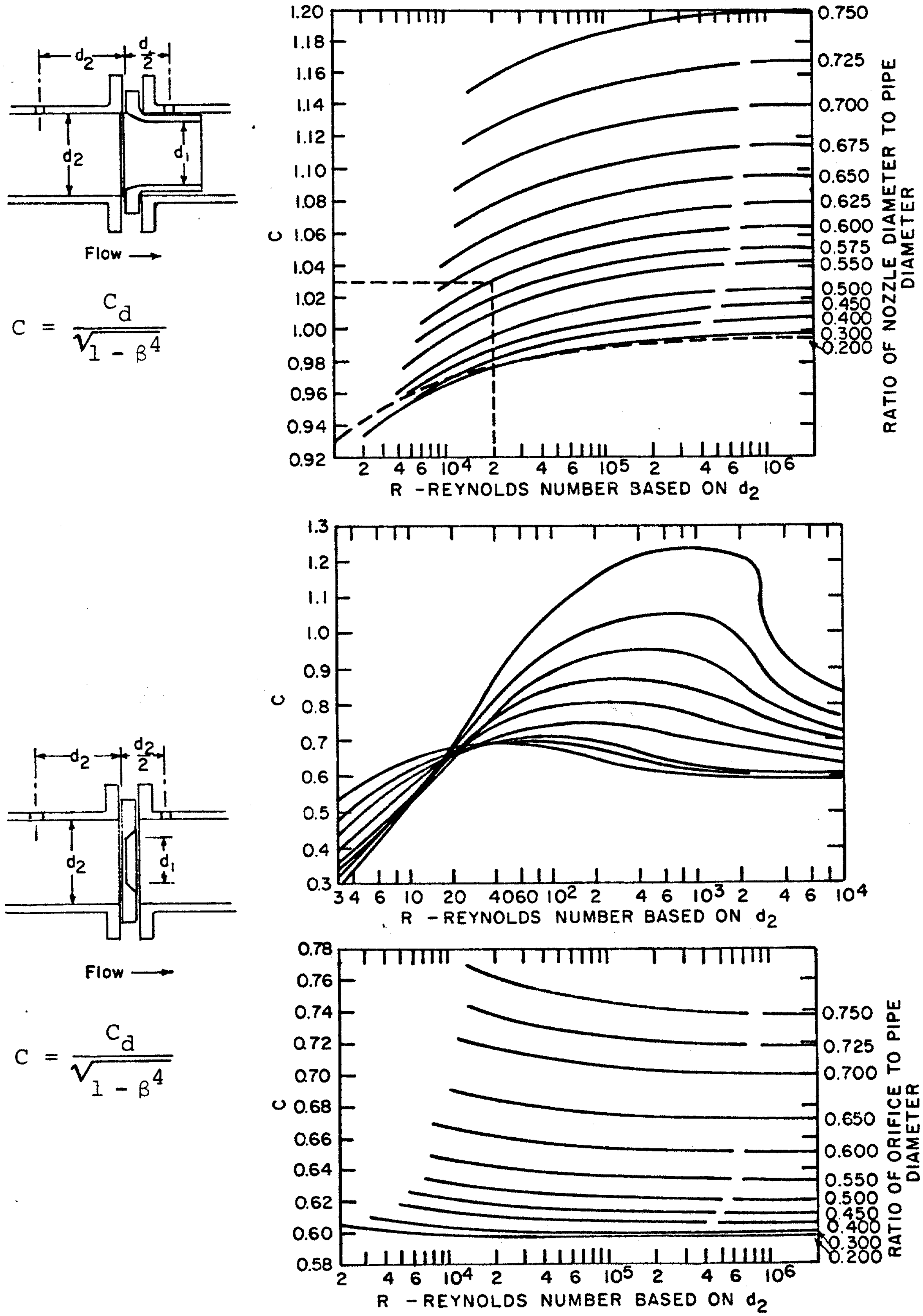


Figure 2.1 - Flow Coefficient For Nozzles & orifices (after Crane)

Since $\rho = \gamma_L(62.4 \text{ lbm/ft}^3)$, and changing q to the unit of gallons per minute:

$$q = CA_o \sqrt{\frac{2g_c \Delta p(144)}{62.4\rho_L}} \quad (7.48)(60) \text{ gal/min}$$

If the constants, including g_c, are brought outside the radical:

$$q = 5471 \; CA_o \sqrt{\frac{\Delta p}{\gamma_L}} \qquad (2.5)$$

where q = flow rate, gal/min

Δp = pressure drop, psi

A_o = area open to flow, ft^2

γ_L = specific gravity (water = 1.00), dimensionless

In an effort to characterize the pressure drop across a valve for any rate of flow, the valve industry uses a parameter called the valve coefficient,[4,5] C_v. For steady-state flow, this coefficient is assumed to be constant for a given valve opening, regardless of the flow rate or pressure drop across the valve. By definition, C_v is the flow rate of water in gallons per minute at 60°F through a valve, or fitting, for a 1 psi pressure drop across the valve.

Beginning with the Darcy-Weisbach equation:[3]

$$\Delta p = \frac{fL\rho v^2}{2g_c D} \qquad (2.6)$$

terms may be rearranged to give:

$$\Delta p = \frac{fL\rho q^2}{1.234 g_c D^5} \tag{2.7}$$

where Δp = pressure drop across length L, lb_f/ft^2

f - Moody Friction Factor, dimensionless

L = length of interest, ft

ρ = density of fluid, lbm/ft^3

q = flow rate of fluid, ft^3/sec

D = internal diameter of pipe, ft

Using more convenient units and, once again, $\rho = \gamma(62.4\ lbm/ft^3)$:

$$\Delta p = \frac{1}{890.5} \frac{fLq^2\gamma_L}{D^5} \tag{2.8}$$

where Δp = psi

L = inches

γ_L = specific gravity, dimensionless

q = gallons per minute

D = inches

For pipe, the valve coefficient is defined as:[4]

$$C_v = \frac{29.9\ D^2}{\sqrt{fl/D}} \tag{2.9}$$

where C_v = valve coefficient, gal-in/min-lb_f

D = internal diameter of pipe, inches

f = Moody friction factor, dimensionless

L = length of pipe, inches

Combining equations 2.8 and 2.9:

$$\Delta p = \gamma \left(\frac{q}{C_v}\right)^2$$

or

$$q = C_v \sqrt{\frac{\Delta p}{\gamma_L}} \tag{2.10}$$

where q = flow rate, gal/min

Δp = pressure drop, psi

γ_L = specific gravity of fluid, dimensionless

If Equation 2.10 is considered along with Equation 2.5, the valve coefficient, C_v is equal to 5471 CA_o where A_o is the area open to flow in square feet. It should be realized that the lack of length and diameter terms is due to their insignificance when considering valves and chokes, whose nominal sizes do not reflect the size of the orifice.

In the valve industry, valve coefficients are determined experimentally using pressure drop-flow rate data, as shown in the following example.

Example 2.1

Compute the value of C_v given the data below.

Density (lb/gal)	Flow Rate (gal/min)	Pressure Drop (psi)
8.92	50	100

Since the density of water is 8.33 lb/gal:

$$\gamma_L = \frac{8.92}{8.33} = 1.07$$

Using Equation 2.10:

$$C_v = 50\sqrt{\frac{1.07}{100}} = 5.17$$

Cameron Iron Works, Inc.,[6] Houston, Texas, has developed a "Mud Bean Selector." This is a slide rule device which allows the user to select the proper bean size for a given pressure drop across the bean. The flow rate and mud weight are the only variables required for operation of the Mud Bean Selector. The formula used to develop the Cameron Mud Bean Selector is:

$$q = 109.7\ CA\sqrt{\frac{\Delta p}{\rho}} \qquad (2.11)$$

where q = flow rate, gal/min

C = flow coefficient (approximately 0.93 for Cameron Type HY and BJ beans), dimensionless

A = orifice area, in^2

ρ = mud weight, lb/gal

Δp = pressure drop across bean, psi

By conversion to the appropriate units, it can be shown that this equation corresponds to Equation 2.5. Cameron states that Equation 2.11 may be used to make calculations beyond the range of the Mud Bean Selector slide rule as well as in making approximations for setting an adjustable choke.

In reviewing published sales literature[7] from Cameron Iron Works, one will find other forms of Equation 2.5. These are all easily converted to Equation 2.5 by rearranging terms or changing units. Cameron, however, utilizes the valve coefficient C_v for sizing and comparing valve flow capacities, and for analyzing experimental flow-pressure data.

E. B. Pool[5] has proposed a "friction area" coefficient, A_f, as an improvement over C_v for incompressible flow capacity. Pool states that there are two disadvantages to the use of C_v. The first disadvantage is due to the unusual dimensions of C_v, arising from the combination of constants in the flow equation with a dimensionless coefficient and an area term. This causes great difficulty in converting to other flow units such as lb/sec or kg/sec. Secondly, C_v's are directly additive for a series of valves, pipe, and fittings only for parallel systems. However, this is not generally useful since pure parallel systems are almost non-existent.

From the Darcy-Weisback Equation (2.6), terms can be rearranged to obtain:

$$f \frac{L}{D} = \Delta p \quad \frac{\rho}{B} \left(\frac{Ai}{m}\right)^2 \tag{2.11}$$

where f = pipe friction factor

L = length of pipe, ft

D = pipe diameter, ft

Δp = pressure drop, psi

ρ = density, lb/ft^3

m = mass flow rate, lbm/sec

B = constant, $144/2(32.174) = 2.238$

From here Pool develops his alternate flow parameter. He proposes that capacity be measured as friction area, A_f, in either square inches or square centimeters, as follows:

$$A_f = m\sqrt{\frac{B}{\rho\Delta p}} \tag{2.12}$$

Pool defines A_f as "the fictitious area which makes the velocity pressure equal to the pressure loss for a valve or fitting." He states that the sole disadvantage in the use of friction area is that the factors cannot be directly added for a series of pipes and fittings, but can be added as:

$$p = \frac{B}{\rho} m^2 \left[\frac{1}{A_{f1}^{\;2}} + \frac{1}{A_{f2}^{\;2}} + \frac{fL/D}{A_i^{\;2}} + \text{etc.}\right] \tag{2.13}$$

The term $1/A_f^{\;2}$ could well be used as the flow parameter to resolve this disadvantage, but the range of values A_f will take on would very well render values of $1/A_f^{\;2}$ impractical. Consider a size 48 gate valve which may have an A_f equal to 5000. Then, $1/A_f^{\;2}$ would be 0.00000004, causing many problems for both people and calculators not capable of handling scientific notation.

For incompressible flow, Pool says that A_f has the following advantages over all other parameters for measuring the flow properties of valves and fittings:

1) Avoidance of equating to pipe friction which is more variable with Reynolds number.
2) Avoidance of ambiguity in reference area inherent in dimensionless coefficients.
3) Manageable valves (0-10,000) for all commercial sizes, at all valve positions.
4) Easy conversion to metric units (in^2 to cm^2)

The friction area, A_f, in square inches may be compared to the valve coefficient, C_v, by the following relationship:

$$A_c = \frac{C_v}{38} \tag{2.14}$$

where

$$38 = \frac{(144\ \frac{in^2}{ft^2})(60\ \frac{sec}{min})}{(231\ in^2/gal)} \sqrt{2(32.174\ \frac{lb_m\text{-}ft}{lb_f\text{-}sec^2})(0.01605\ \frac{ft^3}{lb_m})}$$

2.2 Single-Phase, Compressible Flow

When considering the flow of compressible fluids through nozzles and orifices, the steady-state energy equation is usually coupled with the continuity equation and the isentropic equation of state.[2] This results in an equation quite similar to that for liquids

(Equation 2.4), with the exception that a net expansion factor, Y, is included. The expansion factor is a function of:

1) The specific heat ratio, k
2) The ratio of orifice or throat diameter to inlet diameter, d_o/d_1
3) The ratio of downstream to upstream absolute pressures.

Figure 2.2 gives values for the net expansion factor, Y, and it is quite apparent that these values are always less than one. The values of Y are also identical for a venturi and nozzle, but differ for an orifice. For an orifice, Y may be obtained either by the use of Figure 2.2, or by the following equation:[2]

$$Y = [0.41 + 0.35 \left(\frac{d}{D}\right)^4] \left(\frac{1}{k}\right) \left(\frac{\Delta p}{p_1}\right) \qquad (2.15)$$

where d = orifice diameter, inches

D = upstream tubing diameter, inches

k = ratio of specific heats, C_p/C_v

The equation for compressible flow of gases is:[2]

$$q = YCA_o \sqrt{\frac{2g_o \Delta p(144)}{\rho_o}} \qquad (2.16)$$

where ρ_o = density in the choke throat, lbm/ft^3

q = flow rate, ft^3/sec

A_o = area of the choke open to flow, ft^2

C = flow coefficient, dimensionless

Δp = pressure drop across choke, psi

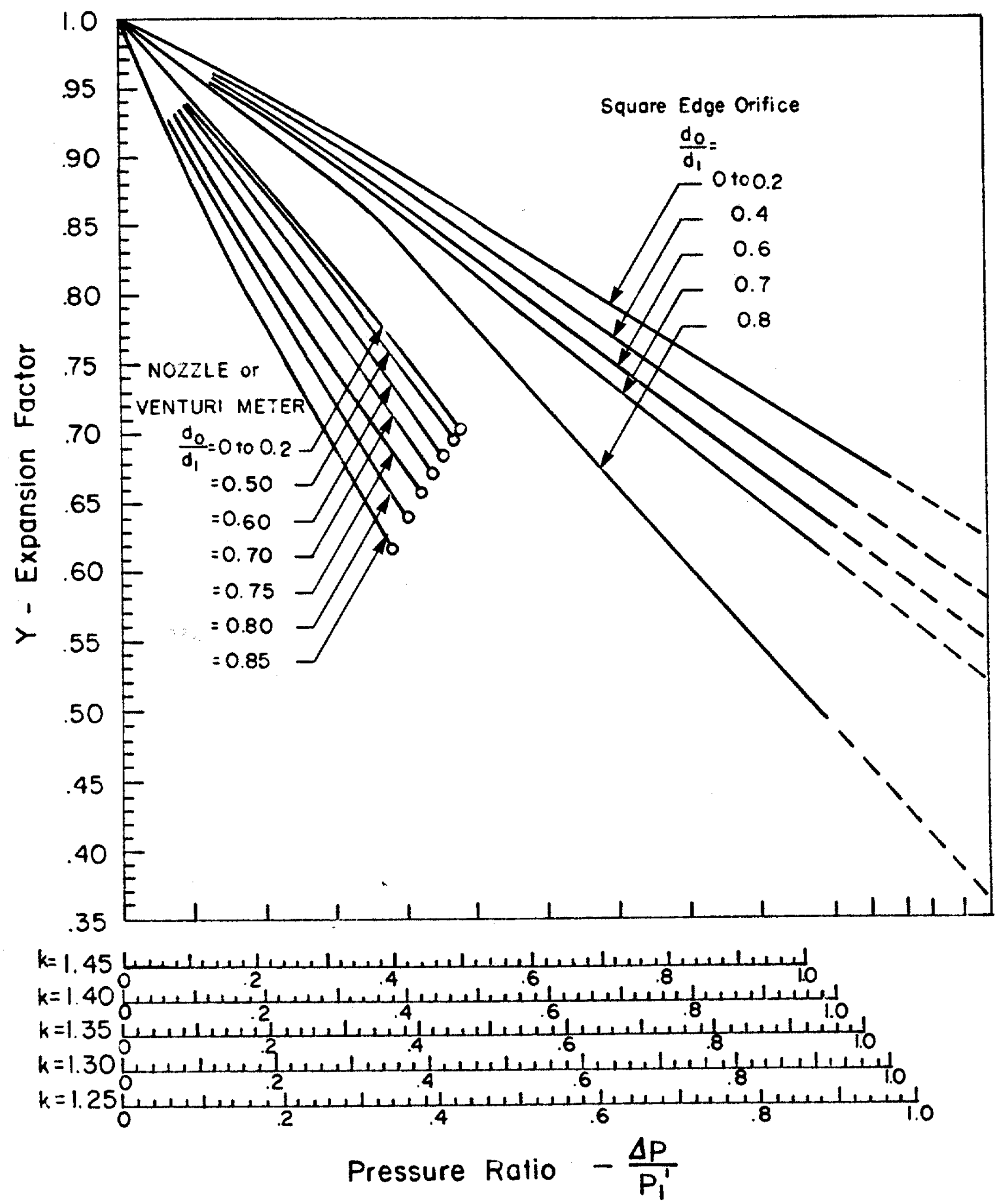


Figure 2.2 - Net Expansion Factor For Compressible Flow Through Nozzles and Orifices (after Crane)

Cook and Dotterweich[9] made use of an equation for the flow of a gas through positive flow beans. A flow bean can be thought of as a very short (less than one foot in length) piece of heavy-walled pipe. Because of the small diameter of the flow channel through the bean (measured in sixty-fourths of an inch), the flow bean is capable of restricting flow, and thus putting backpressure on the well. As mentioned earlier, the bean size refers to the internal diameter of the circular passage in the flow bean.

In their work on flow beans manufactured by Thornhill-Craver Company of Houston, Texas, Cook and Dotterweich obtained discharge coefficients by employing:

$$q = \frac{155.5\ c_d A p_1 \sqrt{2g \frac{k}{k-1} (r^{2/k} - r^{k+1/k})}}{\sqrt{\gamma T}} \qquad (2.17$$

where q = gas flow in MCF/day at 14.65 psia and 65°F

D_d = discharge coefficient (determined experimentally)

A = area of choke, in^2

p_1 = upstream pressure, psia

q = 32.17 ft/sec^2

p_2 = downstream pressure psia

$k = C_p/C_v = \frac{\text{specific heat at constant pressure}}{\text{specific heat at constant volume}}$

$r = p_w/p_1 \geq r_o$

$r_o = (\frac{2}{k+1})^{k/k-1}$ = critical flow pressure ratio

γ = specific gravity (1.00 for air)

T = inlet temperature, °R

Table 2.1 lists average values of the discharge coefficients obtained by Cook and Dotterweich.

Equation 2.17 is a basic formula derived for the calculation of gas flow through convergent nozzles. It is assumed that flow is isentropic, that is, the flow is frictionless, and heat is neither lost nor gained. Since any rapid, (almost) frictionless process occurs with little heat transfer, the assumption is logical. The flow of gas through an orifice or nozzle-like device is a good example of this type of process.

Pool[5] introduces yet another flow parameter to which he gives the name "Nozzle Area." Much like the discharge coefficient equations, where the expansion factor, "Y", is introduced into equation 2.4 (for incompressible flow) to obtain equation 2.16 (for compressible flow), Pool introduces the expansion factor into his incompressible flow equation (Equation 2.11) to obtain:

$$\Delta p = (\frac{m}{YA_i}) \frac{B}{\rho_i} (f\ L/D) \tag{2.18}$$

The nozzle area, A_n, is computed using a series of curves which Pool displays in his paper. He provides steps for which the ratio, A_n/A_i, may be obtained. By

TABLE 2.1

FLOW AND DISCHARGE COEFFICIENTS

FOR 6-IN. LONG CHOKES

Nominal diameter, in.	Area A, sq. in.	Discharge coefficient C_d	AC_d
2/64	0.000767	0.613	0.0004702
3/64	0.001726	0.650	0.001122
4/64	0.003067	0.677	0.002076
5/64	0.00497	0.700	0.003479
6/64	0.00690	0.721	0.004975
7/64	0.00939	0.730	0.006855
8/64	0.01230	0.757	0.009311
12/64	0.02761	0.805	0.02223
16/64	0.0491	0.832	0.04085
20/64	0.0767	0.832	0.06381
24/64	0.1104	0.832	0.09185
28/64	0.1506	0.828	0.1247
32/64	0.1963	0.828	0.1625

knowing the inlet area, A_i, the nozzle area is easily calculated.

2.3 Multiphase Flow

The majority of the correlations available today for multiphase flow across chokes are only valid for critical flow. Recall that critical flow of a fluid is defined as a fluid flow at a velocity equivalent to the velocity (frictionless) of propagation of a pressure (sound) wave in the fluid medium. Critical flow for gases occurs approximately when the ratio of the downstream pressure to the upstream pressure is 0.528.[8]

It is very difficult to find correlations which can be used generally for different fluid types, especially for sub-sonic flow.

One of the very first developments in the area of two-phase flow through restrictions was published by R. F. Tangren, C. H. Dodge, and H. S. Seifret.[3,8] This resulted in an equation of state and one of motion for gas-water mixtures flowing through a "de Laval" nozzle at critical flow conditions.

Tangren et al were to show that when gas bubbles are added to an incompressible liquid, the mixture becomes compressible. Furthermore, above the critical flow velocity, the medium becomes incapable of transmitting pressure changes upstream against the flow.

This was a very important conclusion since production chokes were commonly selected to be installed on a flowing well in such a way that critical flow velocity was attained. Hence, pressure variations due to downstream flow lines and vessels would not affect the production of the well.

The equations developed were based on basic fluid mechanics principles, and all degenerated to familiar equations for single-phase flow.

Gilbert, Ros, Baxendell, and Achong proposed equations which are of the form:[3]

$$p_1 = \frac{A q_L R_p^{\,B}}{d^C} \tag{2.19}$$

where p_1 = upstream pressure in psig (or psia for Ros)

q_L = liquid production rate, STBL/day

R_p = producing gas-liquid ratio, scf/STBL

d = diameter of choke, 64ths of an inch

A,B,C = empirical coefficients listed in Table 2.2

These correlation coefficients were determined using production data from various fields, and are limited in their use to fluids similar to those produced by the fields. These equations are also limited to the type of restriction used, which may or may not

Table 2.2

Empirical Coefficients For Two-Phase

Critical Flow Correlations

CORRELATION	A	B	C
Gilbert	10.00	0.546	1.89
Ros	17.40	0.500	2.00
Baxendell	9.56	0.546	1.93
Achong	3.82	0.650	1.88

allow for their use to describe flow behavior through a drilling choke.

Gilbert,[8] in 1954, developed his equation using daily individual well production data from the Ten Section Field in California. His equation is to be used as the first approximation in a trial-and-error type procedure for selecting a suitable bean size.

However, Gilbert noted that an error of 1/128 inches in bean size can give errors from 5 to 20% in pressure estimates. He further stated that his formula was applicable when the downstream pressure was less than 0.7 of the upstream pressure.

No downstream pressure is used in Equation 2.19 since, as stated before, for critical flow, the production rate or fluid throughput is independent of the pressure downstream from the choke.

Achong's correlation[3,8] for flow through a choke was developed much like that of Gilbert's. Achong used field production data from the Lake Maracaibo Field in Venezuela. He derived accurate constants for the condition and type of beans (Cameron-positive type) for critical flow.

Ros,[3,8] in 1960, developed a flow-meter formula for critical gas-liquid flow through a restriction based on the analysis of the energy balance equation. Poettmann and Beck,[3] in 1963, expressed the Ros equation in oil field units:

$$q_o = \frac{86,400CA}{5.61\,{}_{LS} + 0.0765\gamma_g R_p} \sqrt{\frac{9273.6p}{V_L(1 + 0.5m_L)}}$$

$$\times \quad \frac{0.4513\sqrt{R + 0.7660}}{R + 0.5663} \qquad (2.20)$$

$$\text{where } R = \frac{0.00504Tz(R_p - R_s)}{B_o p}, \quad \rho = \rho_1/4636.8$$

$$m_L = \frac{1}{(1 + R\,\rho_g/\rho_L)}$$

$$V_L = m_L/\rho_L$$

q_o = bbls of stock tank oil/day

C = discharge coefficient (1.03)

A = cross sectional area of throat, in^2 (throat is minimum cross section at area of choke)

ρ_{LS} = density of crude in lb/ft^3 @ 60°F, 14.7 psia

γ_g = specific gravity of gas @ 60°F, 14.7 psia (Air = 1.00)

R_p = gas-oil ratio in scf of gas per bbl of stock tank oil

p_{wn} = tubing pressure, psi

p_1 = tubing pressure in lb_f per square foot

V_L = volume of liquid per unit mass of total fluid, ft^3/lb_m

m_L = mass of liquid per unit mass of total fluid (dimensionless)

T = tubing temperature (absolute) assumed to be 85°F(545°R)

z = compressibility factor of gas at tubing pressure and 85°F

R_s = solubility of gas in crude at tubing pressure and 85°F

B_o = formation volume factor of crude at tubing pressure and 85°F

ρ_L = density of crude at pressure, p, and 85°F, lb_m/ft^3

ρ_g = density of gas at pressure, p, and 85°F, lb_m/ft^3

Equation 2.20 contains some modifications to include the possibility of three-phase flow. Analysis of Equation 2.19 coupled with Equation 2.20 suggests that Q_o, p, or A can be obtained given the other two variables.

The use of Equation 2.20 and of an empirical correlation for determining R_s and B_o allowed Poettmann and Beck to develop working nomographs[8] for crude oil gravities of 20, 30, and 40° API with no water production. To construct the charts, they assumed a gas gravity of 0.6 and a tubing temperature of 85°F.

Poettmann and Beck checked the accuracy of the nomographs by comparison with field measured production rates for 108 tests covering a wide range of R_p, A, p, and oil gravity. They found that the charts predicted slightly conservative, but acceptable results considering the effect minor choke size deviations can have on production rates.

The choke flow nomographs of Poettmann and Beck may be seen in Figures 2.3, 2.4, and 2.5.

In 1968, yet another multiphase flow correlation was developed by Omana.[3,8] Using carefully controlled experimental data taken at the facilities of Union Oil Company of California's Tigre Lagon Field in Louisiana, he determined through dimensionless analysis that:

$$N_{qL} = 0.263\, N_{\rho}^{-3.49} N_{pl}^{3.19} Q_d^{0.657} N_d^{1.80} \qquad (2.21)$$

where $N_{qL} = 1.84\, q_L \left(\frac{\rho_L}{\sigma_L}\right)^{1.25}$

$$N_{\rho} = \rho_g/\rho_L$$

$$N_{pl} = 1.74 \times 10^4\, p_1 \left(\frac{1}{\rho_L \sigma_L}\right)^{0.5} \times 10^{-6}$$

$$Q_d = \frac{1}{1 + r}$$

$$R = N_{gv}/N_{LV}$$

$$N_d = 120.872 d_o \text{ (ft)} \sqrt{\frac{\rho_L}{\sigma_L}}$$

The following ranges of flow variables were used:

p_1: 400-1000 psig upstream pressure

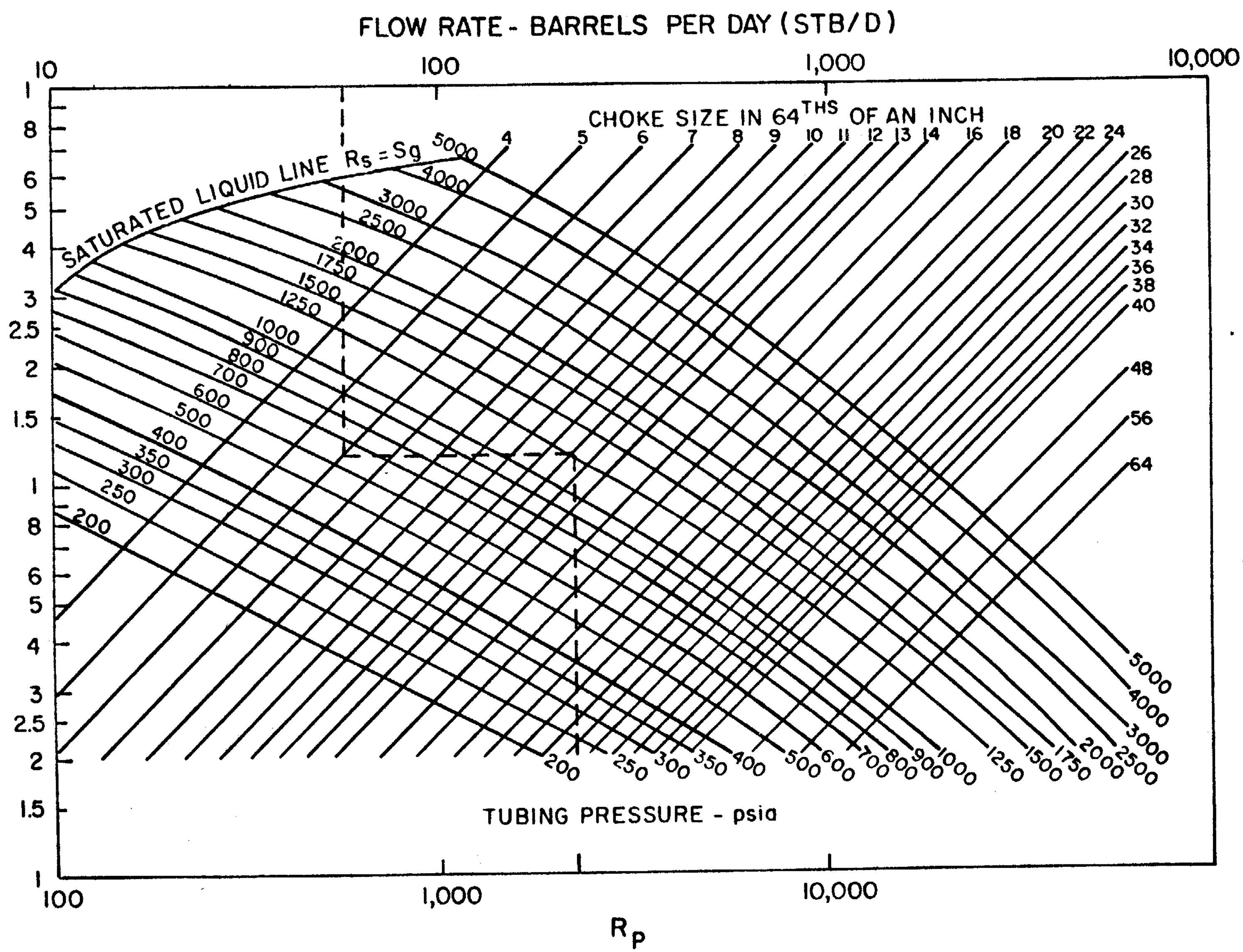


Figure 2.3 - Poettmann and Beck Choke Flow Nomograph (20°API) (After Poettmann and Beck)

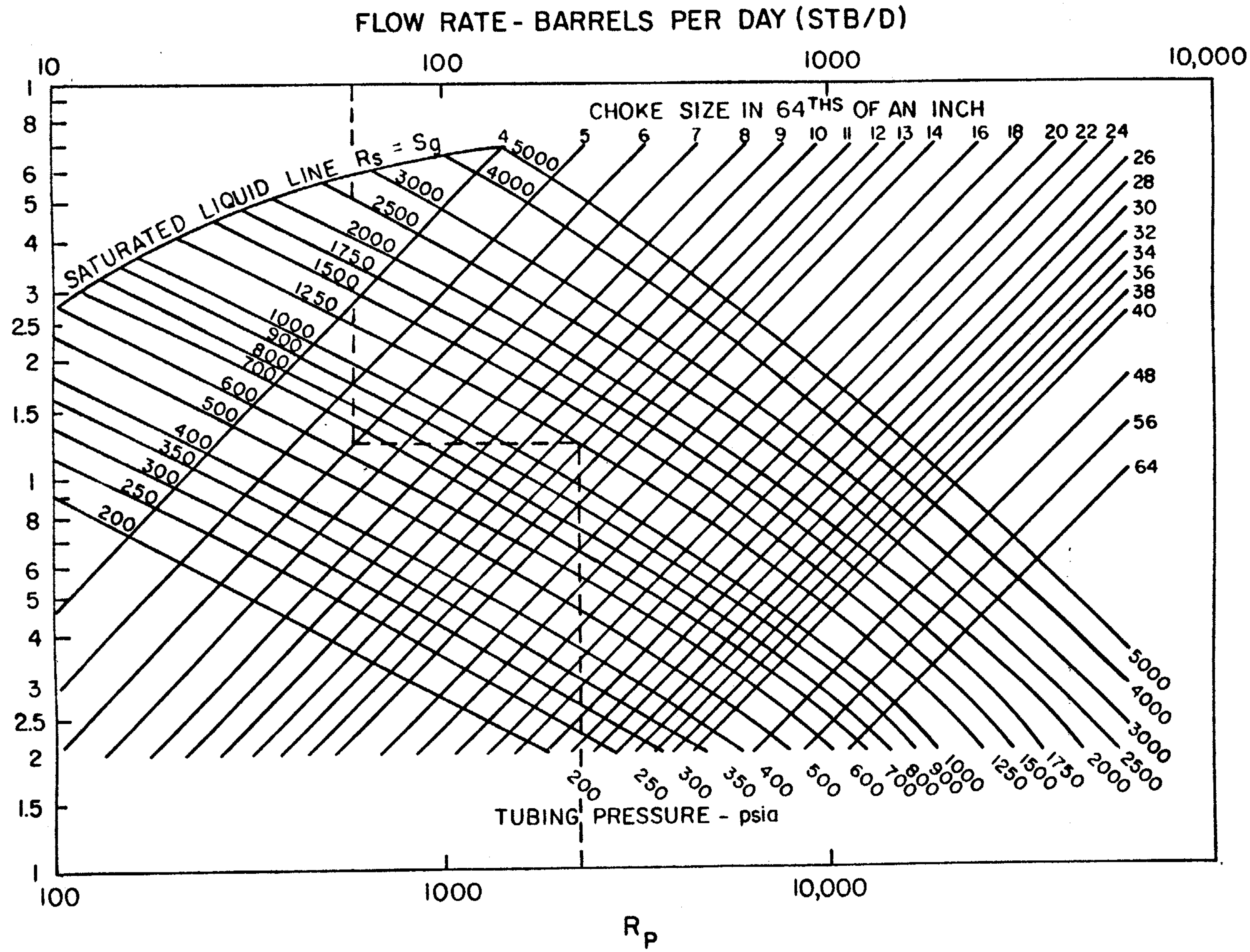


Figure 2.4 - Poettmann and Beck Choke Flow Nomograph (30° API)(After Poettmann and Beck)

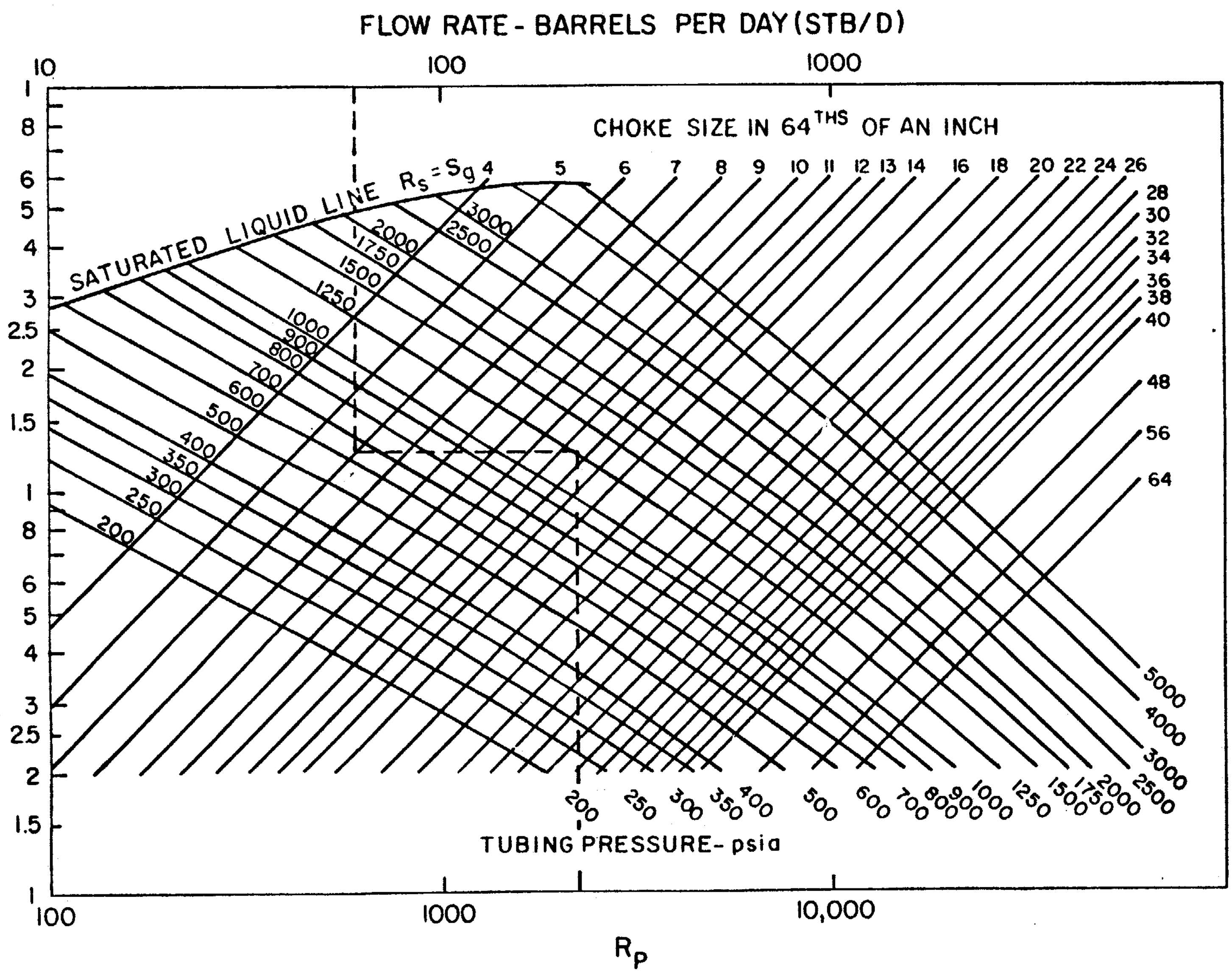


Figure 2.5 - Poettmann and Beck Choke Flow Nomograph (40° API) (After Poettmann and Beck)

p_d: 300-900 psig downstream pressure

d_o: 4, 6, 8, 10, 12 and 14/64 inches

q'_g: 0-7 MMCF/day (0.611 gas gravity)

q'_L: 0-800 SrB/day (water)

Several comments about Omana's correlation may be found in works[3,8] covering multiphase flow. Initally, the use of this correlation should be made with caution when viscous liquids are being considered. Omana determined that the liquid viscosity number, N_L, was unimportant, but this is probably due to the fact that the data base included only water as the liquid phase. Secondly, the limitations in terms of choke size, flow rate, and pressure prevent Equation 2.21 from becoming widely accepted.

Omana stated that his correlation was valid only for critical flow, as the data for which $p_2/p_1 > 0.546$ was not used for the correlation.

For choke sizes less than 14/64 of an inch and viscosities comparable to that of water, Omana's correlation is considered to be very accurate.

It is far more difficult to predict subcritical two-phase flow behavior. A model that can be used to calculate critical and subcritical two-phase flow through chokes was presented by Fortunati,[8] who assumed no slippage between the phases, although he recognized that slippage does exist even for immiscible liquids. Two conditions are required for this assumption to be valid:

1) the mixture velocity should be greater than 10 m/sec (32.78 ft/sec)

2) the Froude number of the mixture must be greater than 600

Figure 2.6 shows curves based on the experimental work of Guzov and Medviediev[8] for describing the relationship between the pressure drop and flow rates for sub-critical two-phase flow. Fortunati used these curves which engaged a downstream pressure of 0.137 MN/MZ or 19.8 psia. The following formula corrects the mixture velocity for actual downstream pressure:

$$v_{m2} = v_{m2F} \left[\sqrt{\frac{p_2}{p_{2F}}} \right]^{\eta} \qquad (2.22)$$

where $\eta = [1 - \lambda_{g2}^{3}]^{0.38}$

The liquid flow rate is then:

$$q_L = A_B (1 - \lambda_{g2}) C_D \, v_{m2} \qquad (2.23)$$

Fortunati suggests that the discharge coefficients, C_D, for subcritical flow vary from 1.020 to 1.035 depending on choke size. His model assumes isothermal flow and that physical properties are calculated at the downstream pressure.

An improved technique for predicting sub-critical

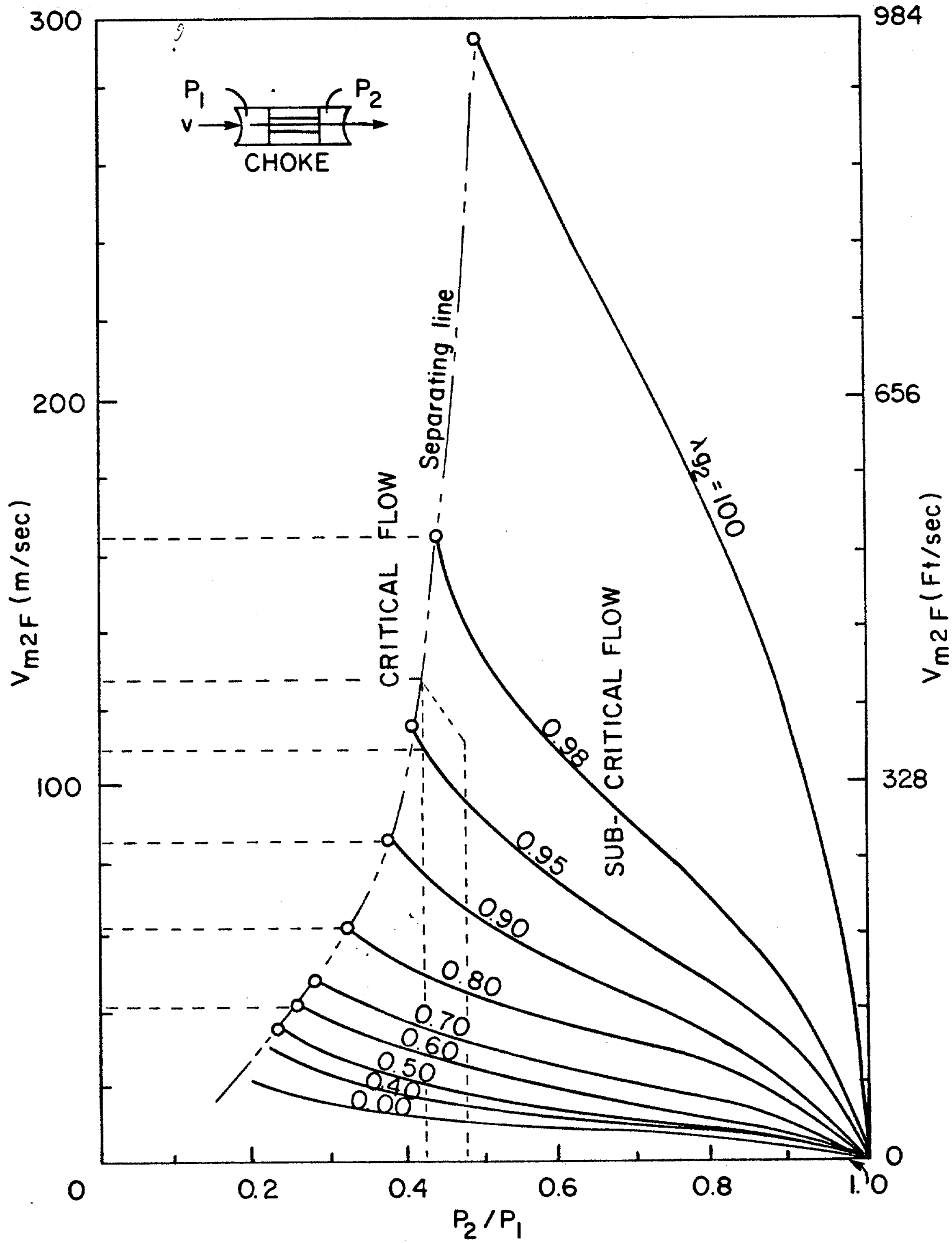


Figure 2.6 - Mixture Velocity for Critical and Subcritical Flow (After Fortunati)

pressure drop across two specific velocity controlled subsurface safety valves was the result of an extensive research program funded by the American Petroleum Institute at the University of Tulsa. Air-water and natural gas-water experiments were conducted through the two inch Otis "J" and Camco "A-3" valves. A homogeneous model for predicting pressure drop was proposed, as follows:

$$\Delta p_{Tp} = \frac{\rho_n v_{mB}^2}{2g_c C_D^2} \tag{2.24}$$

where ρ_n, v_{mB}, and C_D are evaluated at upstream temperature and pressure

Empirical correlations for the discharge coefficients of each valve were developed, and the result was the following relationships

$$C_D = C_o + C_1 R_D + C_2 R_D^2 + C_3 v_D \tag{2.25}$$

where C_D = discharge coefficient

$R_D = d_B/d_t$

$v_D = v_{sg}/v_{sL}$

d_B = bean diameter

d_t = tubing diameter

v_{sg} = gas slip velocity

v_{sL} = liquid slip velocity

Table 2.3 lists the discharge coefficients determined.

TABLE 2.3

EMPIRICAL COEFFICIENTS FOR ORIFICE

DISCHARGE COEFFICIENT CORRELATIONS

	Camco Liquid	Camco Two-Phase	Otis Liquid	Otis Two-Phase
C_o	0.2815	0.5417	1.8247	1.1819
C_1	9.4691	3.8749	-13.9697	-1.8761
C_2	-25.5689	-10.4536	51.0889	0.9922
C_3	-0-	-0-	-0-	-0.0119

2.4 Application of Techniques to Electronic Simulators

Electronic simulators are currently being used to teach drilling personnel the proper procedures for the control of high pressure fluids that have entered the wellbore. A vital part of this training is the operation of the choke. The experience gained through careful manipulation of the drilling choke of the electronic simulator will be beneficial only if that simulator is programmed in such a manner that what occurs in the classroom closely resembles what occurs on the rig floor.

To accomplish these ends, electronic simulator manufacturers must model the drilling choke using some basis for the pressure drop-flow rate characteristics. Use of the correct correlation or calculation technique will provide a drilling choke on the electronic simulator that not only exemplifies the actual well control situation, but also thoroughly trains the individual adjusting it.

Imco,[10] maker of the "Boss Simulator," is one of these manufacturers. The drilling choke on their electronic simulator makes use of the valve coefficient, C_v, for flow of fluids through the choke. Because C_v, as defined, is used for incompressible flow, one may wonder how C_v could be incorporated for gas. It was learned that at that point when gas begins to flow through the choke, the density of the fluid programmed drops to an average gas density, and thus the pressure drops react accordingly.

The C_v's used to program the simulator were obtained from Cameron Iron Works, Inc. These valve coefficients were obtained by Cameron experimentally using water as the flowing fluid. The Cameron High Pressure Remote Choke was used in collecting the empirical data.

CHAPTER III

EXPERIMENTAL APPARATUS AND PROCEDURE

The Louisiana State University Blowout Prevention Training and Research Facility, located on the Baton Rouge, Louisiana Campus, was the site used for this study. A surface layout of this facility and its equipment is shown in Figure 3.1. Figure 3.2 portrays the actual equipment layout used for this study. The test system consisted primarily of a circulating system, the choke manifold, and the data monitoring equipment.

3.1 The Circulating System

Circulation of the different drilling fluids was accomplished using a diesel powered, Halliburton Model T-10 cementing pump equipped with 4.0-inch liners.[11] The 10.0 inch stroke length allowed the pump a 100% efficiency factor of 25.737 strokes per barrel pumped. Tests were run quite often to insure that a constant pump factor could be used. After many tests using different drilling fluids, different flow rates, and different pressure drops across the chokes, an average pump factor of 26.1 strokes per barrel was determined.

Suction for the pump was provided by two 10-barrel metering tanks, adjacent to the pump. The pump could discharge through the flow line to the choke manifold

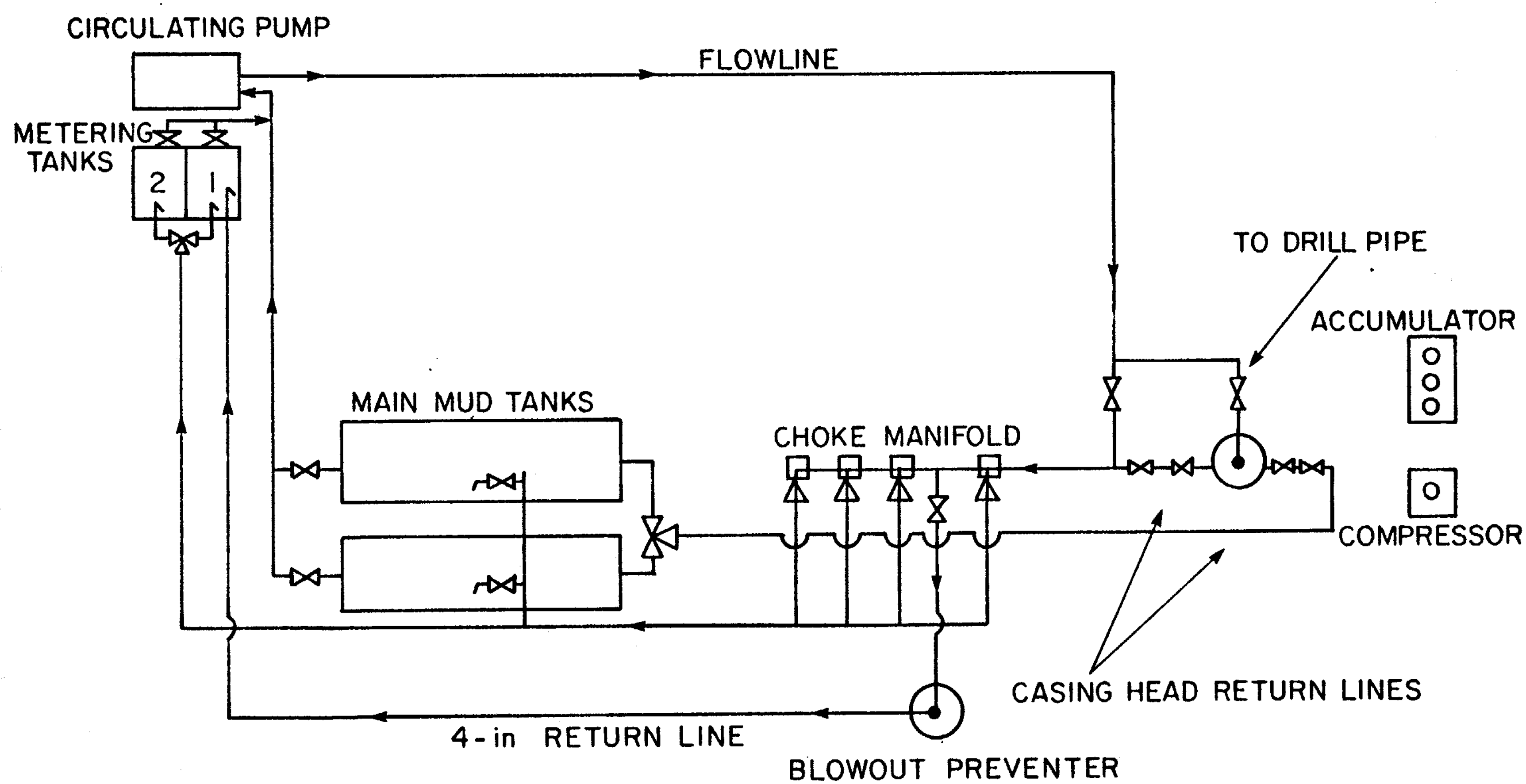


Figure 3.1 - Surface Layout of LSU Research and Training Well (After Doyle)

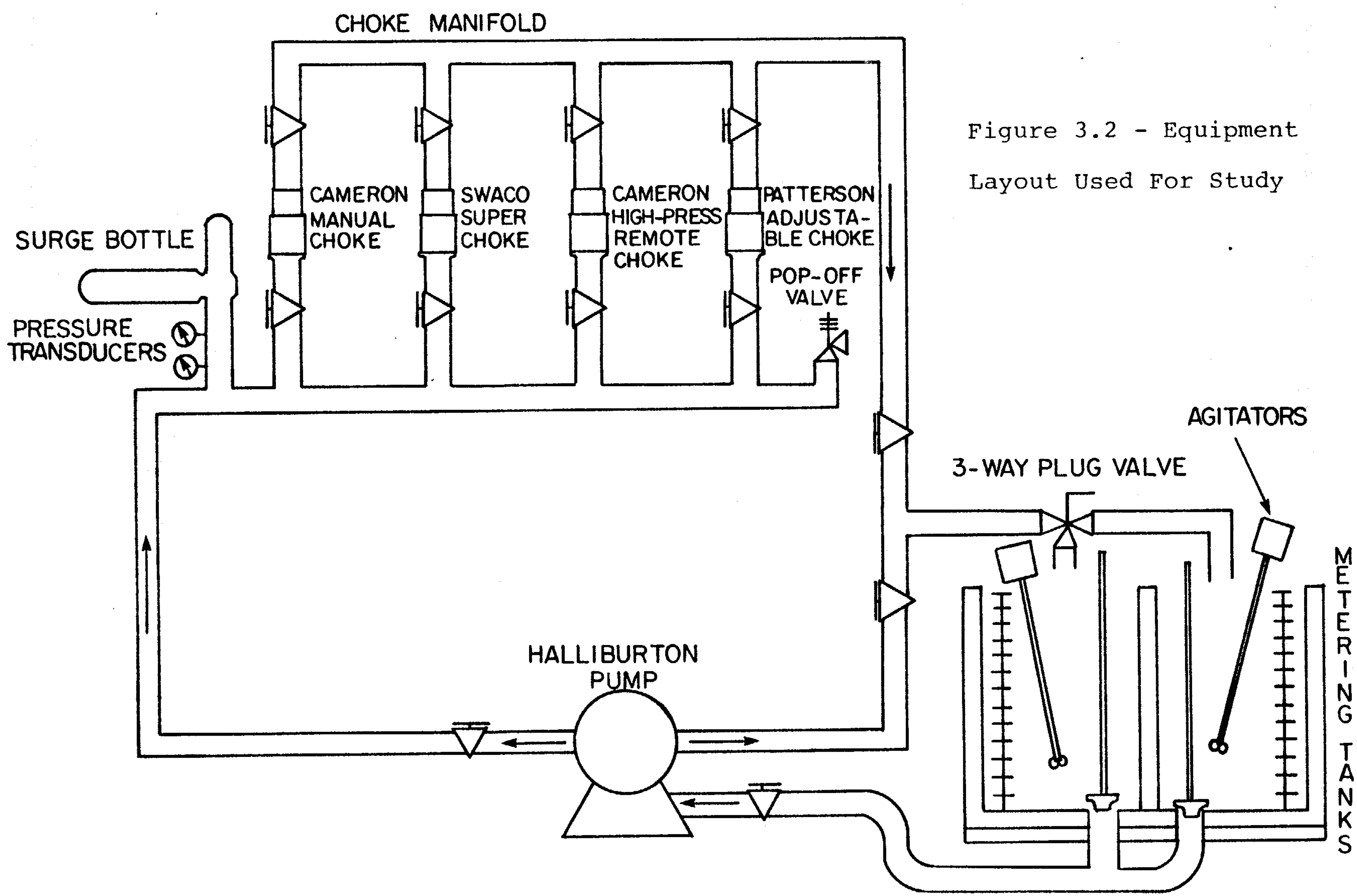


Figure 3.2 - Equipment Layout Used For Study

or back to the metering tanks. This was desired, for the mixing of the drilling fluids was to take place in the metering tanks. To aid in the mixing of the drilling fluids, a Halliburton "Lightnin" Agitator was installed in each of the two metering tanks. This proved to be a successful means of maintaining the rheological properties of the drilling fluids at a somewhat fixed value. The use of the metering tanks also facilitated the measurement of the actual pump factor at any time desired during the experiment.

Pressure fluctuations produced by the stroking action of the pump were dampened, to some extent, by a small surge bottle located on a branch of the flowline just upstream of the choke manifold. It is believed that the fluctuations in pressure were not so severe as to effect the accuracy of the measurements.

3.2 The Choke Manifold

The choke manifold used for this study contained the four chokes for which data was taken, namely, the Cameron Manual Choke, the Cameron High-Pressure Remote Choke, the Swaco Super Choke, and the Patterson Adjustable Choke. Gate valves are set both upstream and downstream of each choke to restrict flow to the choke being investigated at that time. This arrangement is not unusual because, if it were required to remove the choke from the flowline, that branch of the choke manifold can be closed to flow.

Flow regulation is accomplished in a drilling choke by means of a built-in restriction, called an orifice, which can be either fixed or adjustable. Through the use of the adjustable drilling choke, pressure on the choke line can be either reduced or increased depending on the desired pressure at bottom hole. Controlled release of well pressure is a requirement of blowout prevention equipment, and thus the drilling choke is a required part of this equipment. Just as different companies have their own designs for equipment that do similar jobs, in the drilling industry there is quite an assortment of drilling choke designs available. The primary difference in design from one manufacturer to the next lies in the choke elements which adjust the orifice size.

Four of the commercially available drilling chokes were used in this study, and are now discussed individually.

3.3 The Cameron Manual Adjustable Choke

The Cameron Manual Choke, shown in Figure 3.3, is a hand adjustable drilling choke manufactured by Cameron Iron Works, Inc., Houston, Texas.[7]

Flow through this choke is controlled by means of a stainless steel needle and seat assembly. Adjustment of the needle is controlled by turning the hand wheel.

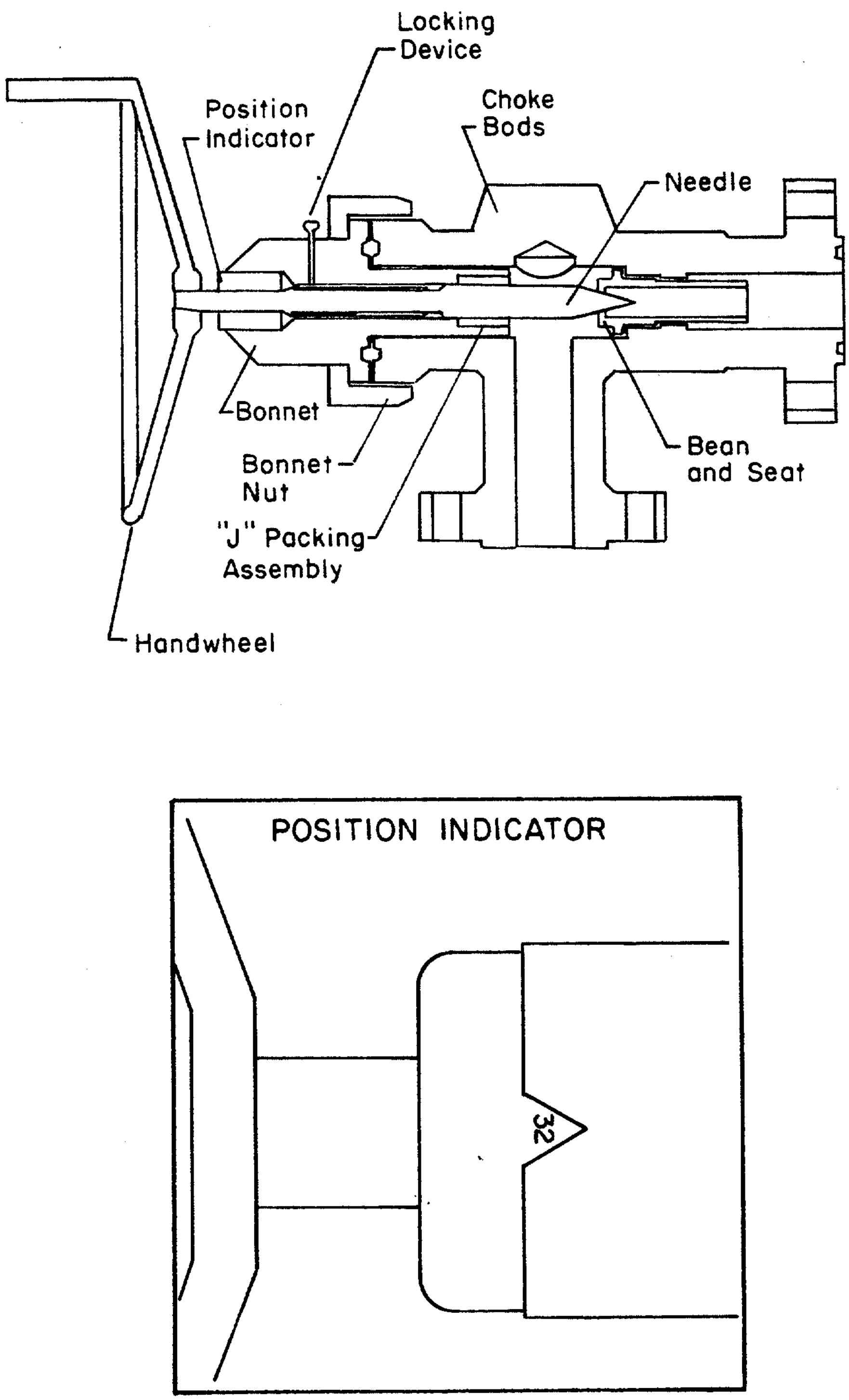


Figure 3.3 - Cameron Manual Choke

(After Cameron)

Because of the threading of the handwheel (eight threads per inch), each 360° turn of the handwheel moves the needle one-eighth of an inch. The equivalent area open to flow is, therefore, directly related to the movement or travel of the needle, and thus to the turn of the handwheel. A choke position indicator (see inset, Figure 3.3) is provided which shows the equivalent orifice diameter in sixty-fourths of an inch. If the setting is "32" as in Figure 3.3, the choke may be considered to have the equivalent of a circular areal opening whose diameter is one-half of an inch.

A locking device consisting of a brass plug and a thumb screw or slot head screw is also provided. This device may be used if it is desired to lock the needle into position once the desired orifice size has been set.

Cameron two inch 2000 to 10,000 psi working pressure chokes feature one-hundred per cent interchangeability of component parts between bodies. The bonnet assemblies, blanking assemblies, beans, and seats are, therefore, interchangeable between these chokes. Lower replacement part inventories and less confusion in ordering parts are a direct advantage of this system.

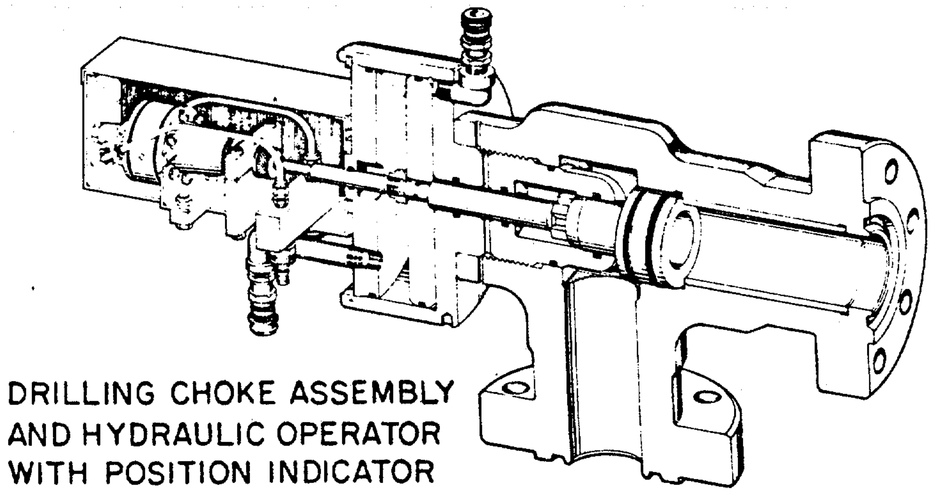
3.4 <u>The Cameron High-Pressure Remote Adjustable Choke</u>

The Cameron High Pressure Remote Choke, shown in Figure 3.4, is a remote adjustable choke rated for a working pressure and temperature of 10,000 psi and 400°F, respectively.[7]

Flow through the choke is controlled by a gate and seat assembly which are both reversible, thus doubling the life of these choke elements. The use of a cylindrical gate, rather than a needle tip, in a large body cavity results in a higher flow capacity with reduced danger of plugging. The gate has a one-half inch long, five degree taper on each end. A one-sixteenth inch, forty-five degree chamfer may be found on the seat. For wear resistance, the choke gate and seat are solid tungsten carbide.

Operation of the choke is by means of a completely pneumatic choke control panel (see Figure 3.5). Rig air is the only necessity for operation of the choke panel, although the panel can function for over six hours on a bottle of nitrogen if rig air fails. An air operated, hydraulic pump is located within the control panel. This pump supplies the 10,000 pound hydraulic force required to open or close the choke gate.

Along with the features displayed on the choke panel in Figure 3.5, an added feature is certainly worth mentioning. A Maximum Allowable Casing Pressure knob enables the setting of a choke manifold pressure above which the choke is automatically opened. This prevents excessive pressures from being erroneously applied to the surface piping.



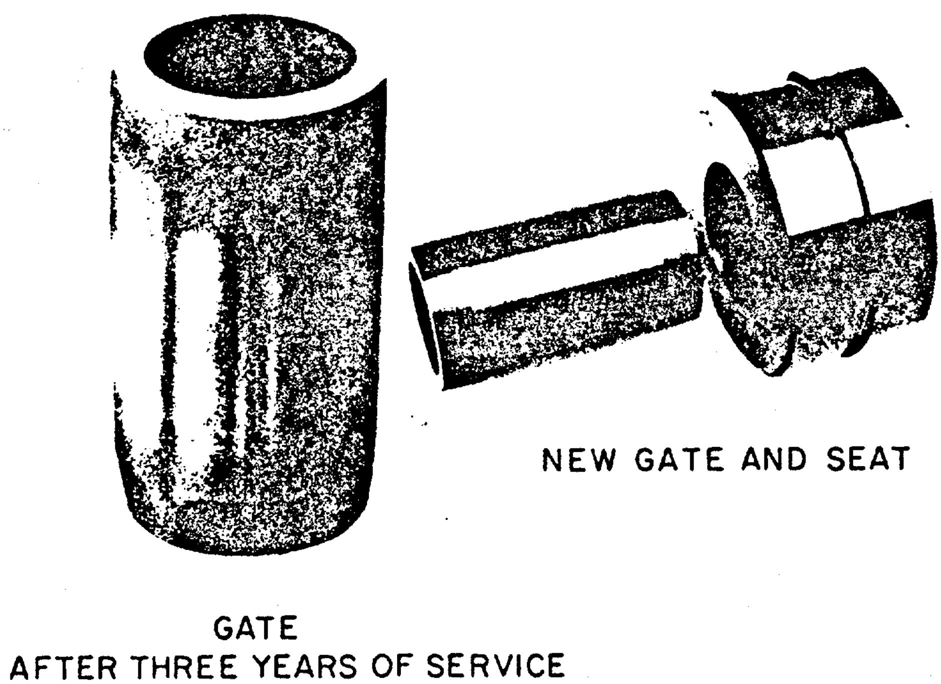


Figure 3.4 - Cameron High Pressure Remote Choke And Gate and Seat Assembly (After Cameron)

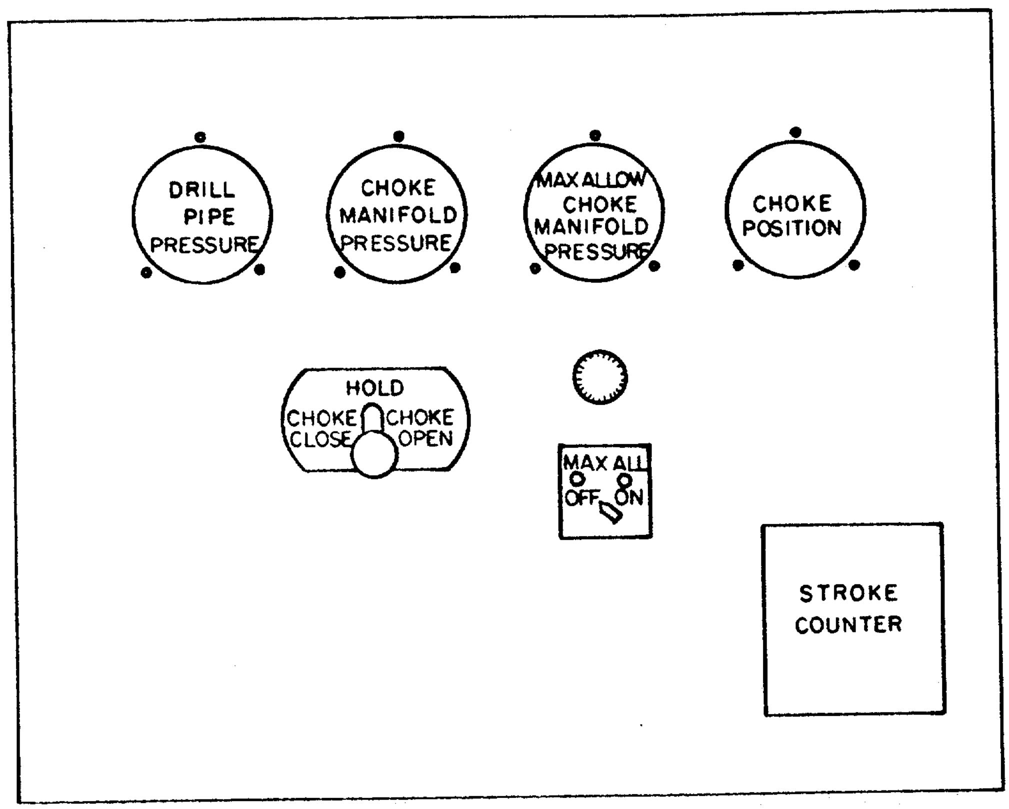


Figure 3.5 - Cameron Remote Drilling Choke Panel

(after Cameron)

The choke control panel has two step-down pressure transmitters which supply it with drill pipe and choke manifold pressures, with an accuracy of $\pm$ 0.3%.

In the sales literature[7] on the Cameron High Pressure Remote Choke, pressure drop data as a function of flow rate is given in graphical form. This data was measured during clean-up operations on twenty different wells, and is shown in Figure 3.6a. Figure 3.6b gives C_v data obtained by Cameron for flow of water through the Cameron High Pressure Remote Choke. Cameron[6] cautions those inquiring into the C_v data that wear on the choke elements can appreciably alter this data. For this reason, it is not wise to set production rates using C_v data obtained from a drilling choke.

3.5 The Swaco Super Choke

Swaco Operations, Oilfield Products Division, Dresser Industries, Inc. of Houston, Texas introduced the Swaco Super Adjustable Choke in 1968.[17] The choke is designed to handle up to 10,000 psi working pressure in the manifold.

The orifice elements of this particular choke are two heavy-duty, tungsten carbide plates, shown in Figure 3.7, along with the cutaway view of the choke. The downstream choke plate is set in a special carrier which receives one-half inch of the first wear sleeve.

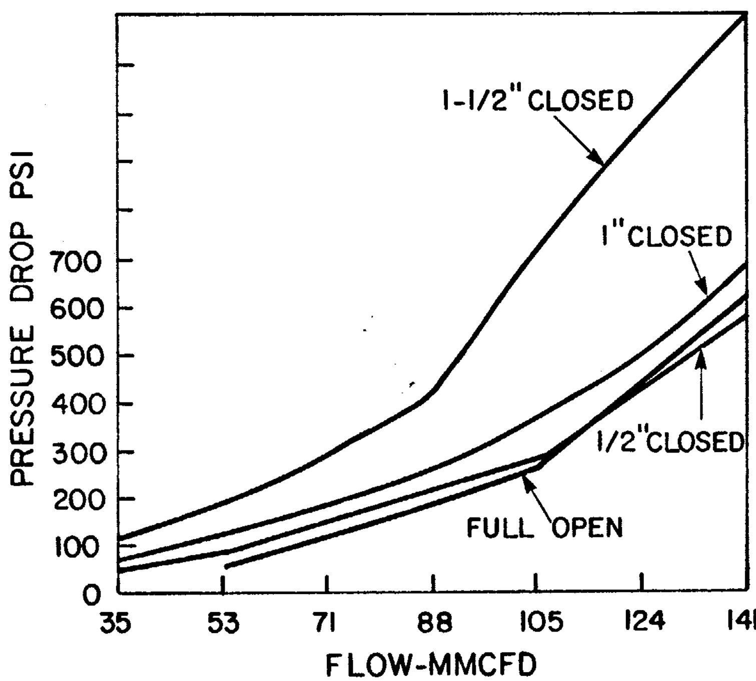


Figure 3.6a - Pressure Drop - Flow Rate Data (after Cameron)

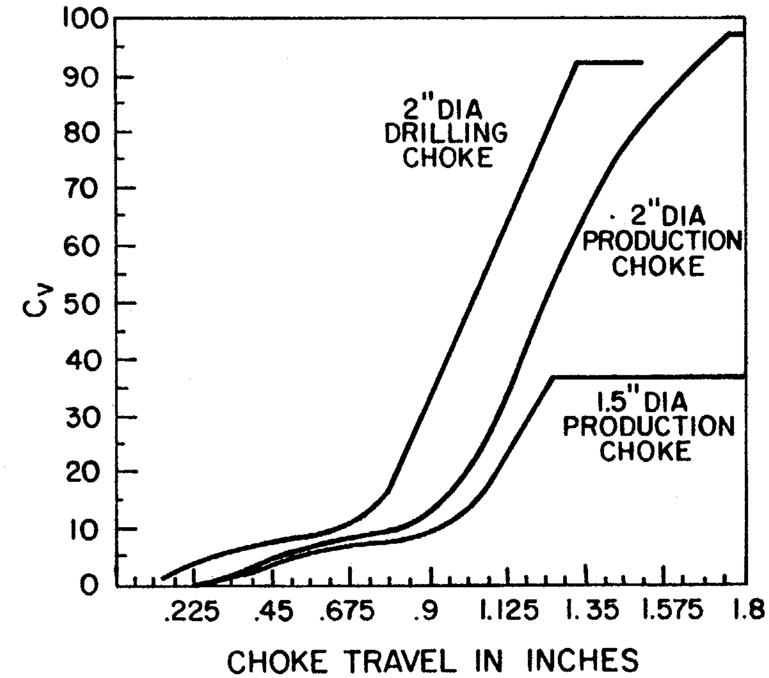


Figure 3.6b - C_v as a Function of Choke Travel (after Cameron)

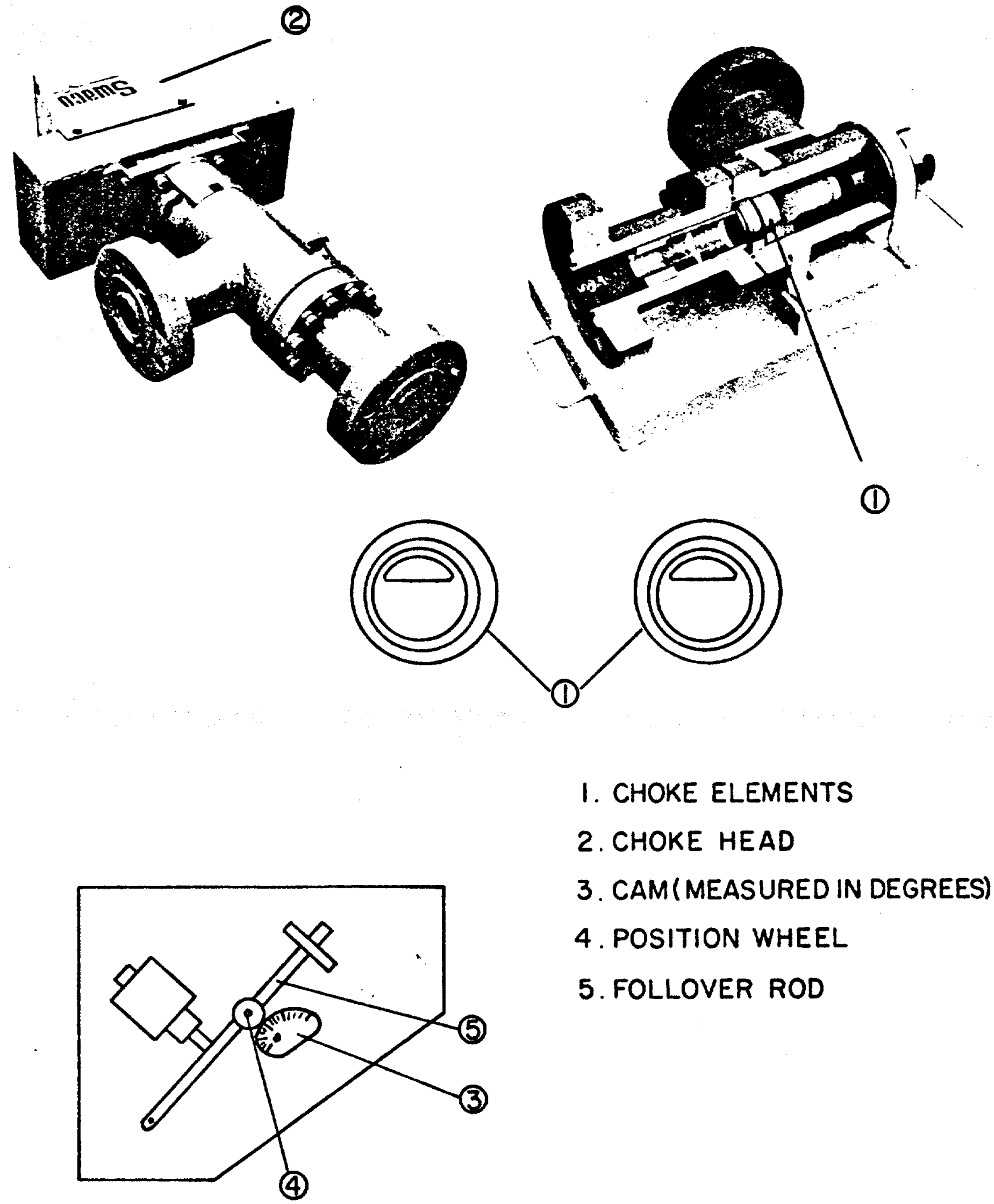
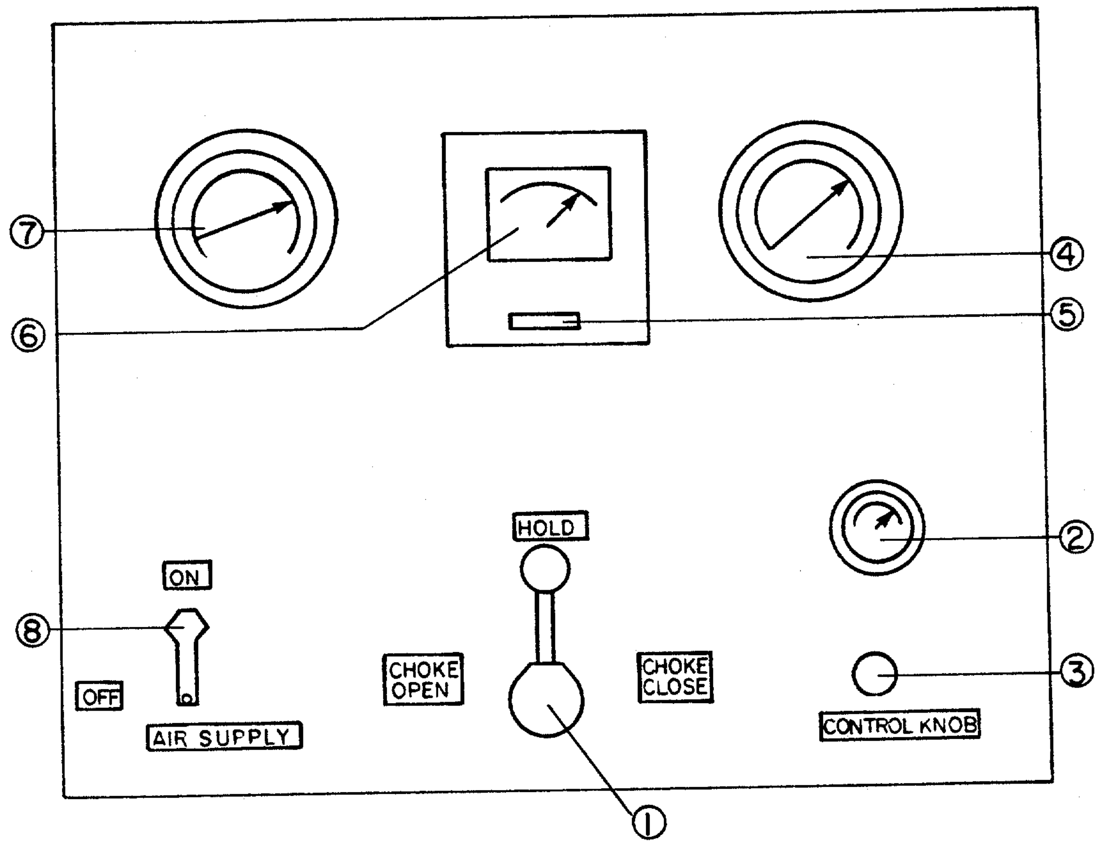


Figure 3.7 - Swaco Super Choke (After Swaco)

This sleeve absorbs the impact of the pressure and abrasives in the fluid as it first passes through the choke plates. It is the rotation of this first choke plate which is responsible for the adjustment of the orifice size. Swaco claims that this rotating action of the plates will effectively shear even large shale carvings. Furthermore, they state that no entrained solids of any description have ever prevented closing of the choke under any circumstances.

The control console which governs operation of the Swaco Super Choke is shown in Figure 3.8. The choke and control console act as a complete, self-contained unit, and may be operated independently of rig power if it becomes necessary. Features of the control console include drill pipe and casing pressure gauges, choke position indicator, pump stroke rate, and continuous pump stroke counter. Skid-mounted lifting hooks are provided with the control console, as it weighs 750 pounds.

Swaco publishes an "Equivalent Bean Size Chart"[17] (Figure 3.9). The approximate bean size, or diameter of the equivalent area open to flow, in inches is plotted for the indicated choke position. As can be seen from Figure 3.9, a range of values is appropriated for each choke position, thus giving a high and low tolerance figure.



① CHOKE POSITION LEVER
② CHOKE POSITION INDICATOR
③ SPEED CONTROL KNOB
④ CASING PRESSURE GAUGE
⑤ PUMP STROKE COUNTER
⑥ PUMP STROKE RATE
⑦ DRILL PIPE PRESSURE GAUGE
⑧ AIR SUPPLY LEVER

Figure 3.8 - Swaco Control Console

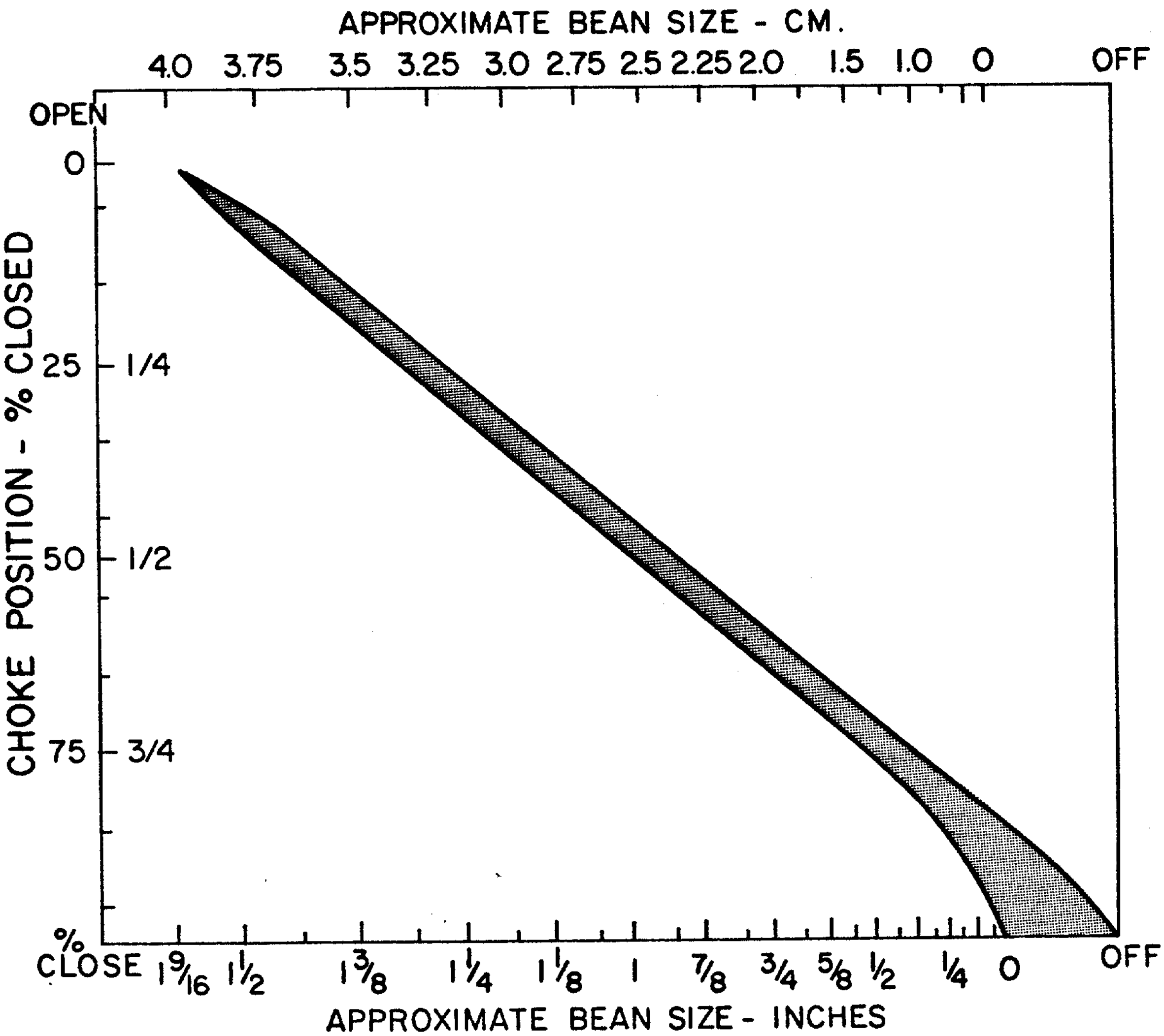


Figure 3.9 - Equivalent Bean Size

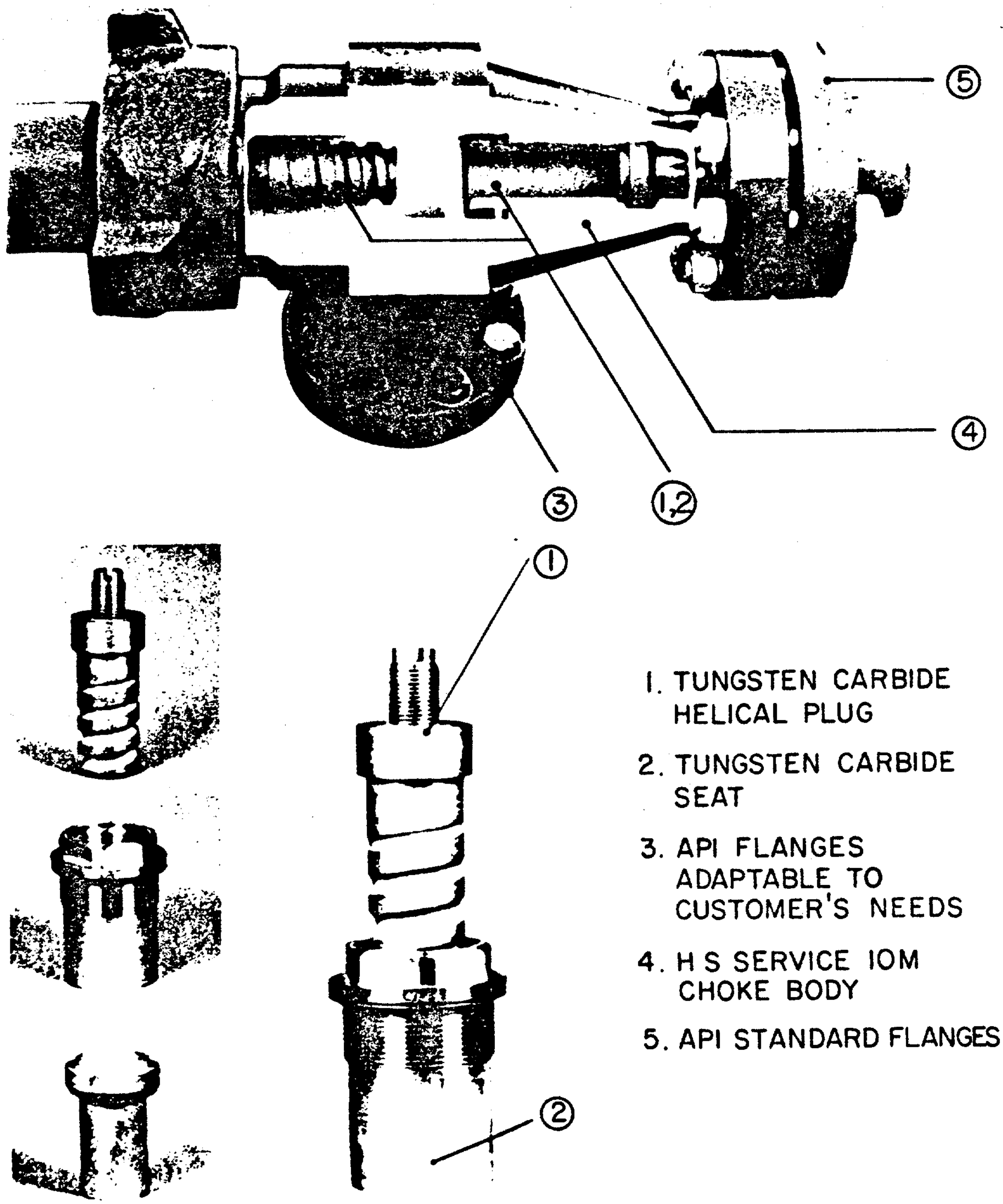


Figure 3.10 - Patterson Adjustable Choke

(After Patterson)

3.6 Patterson Adjustable Choke

The Patterson Adjustable Choke is a hydraulically operated choke designed for a working pressure of 10,000 psi.[17] Shown in Figure 3.10, this drilling choke utilizes a tapered helical plug and seat assembly as the choking mechanism, which provides a continuous range of choke sizes from complete shut-off to about 1.96 inches. The helical plug with declining taper determines the choke size as it is inserted into or withdrawn from the seat with a hydraulic ram of 70,000 pounds end force.

The Patterson Adjustable Choke was designed primarily as a drilling choke to control high pressure gas kicks and salt water flows on drilling wells. Patterson, however, lists the following operations for which the choke can be used:

1) Controlling well kicks
2) Stripping-in under pressure-controlled displacement
3) Spotting light fluids
4) Spotting heavy slugs
5) Drilling under pressure
6) Displacing fluids in wells before and after workover
7) Testing new completions.

Operation of the choke is by means of a control

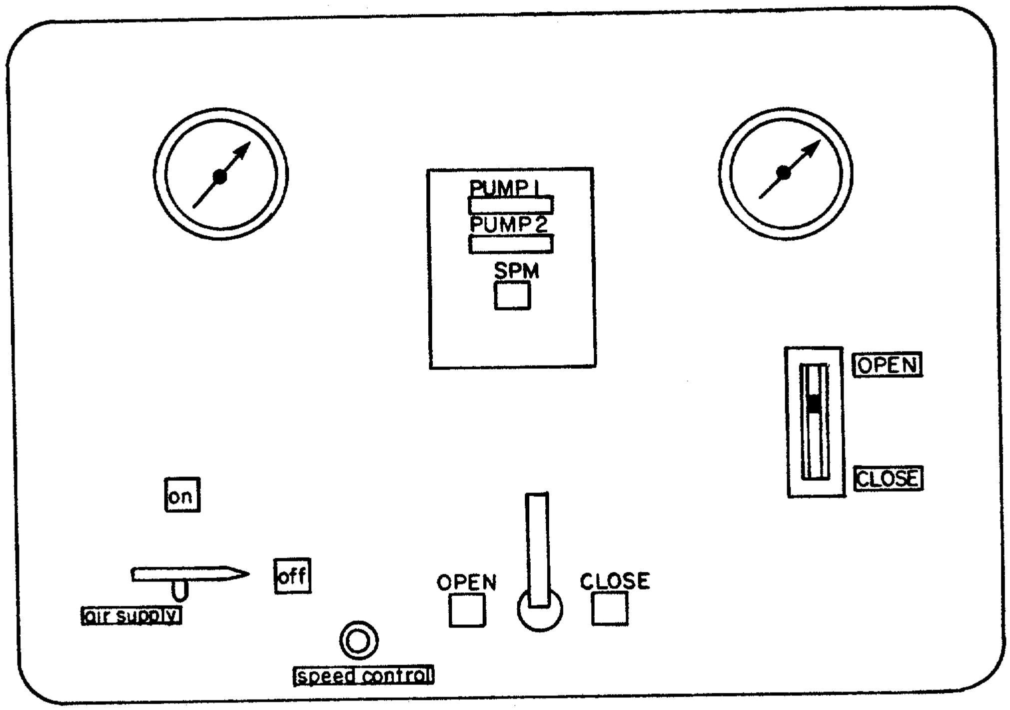


Figure 3.11 - Patterson Adjustable Choke Control Console

console consisting of pump and casing pressure gauges, an air supply lever, a stick valve, a position indicator, and a pump stroke counter with rate (Figure 3.11). The hydraulic pump, hand pump, fluid reservoir, and accumulators may be found below the top section of the control console. One hundred psi of rig air is required to operate the unit.

The control console is all-aluminum. Patterson[15] states that this not only allows maintenance to be practically non-existent, but also offers the advantage of portability. They claim that two people can easily handle a unit.

3.7 Data Monitoring Equipment

The Cameron Remote Choke Panel, The Swaco Control Console, and Patterson Control Console make up the bulk of the data monitoring equipment. Pressure transducers located on a branch of the flowline upstream of the choke manifold send hydraulic signals to the pressure gauges located on these panels. Pressure can be read from either the casing pressure gauges or the drill pipe or pump pressure gauges since both should be identical.

The pump stroke rate and the cumulative pump stroke count are relayed electronically from a transducer located on the pump. In measuring pump stroke rate using the counter and a stopwatch, it was evident that the pump indicator is, indeed, accurate.

A Fann Viscometer, a Mud Balance, and a mercury thermometer were used to measure the properties of the drilling fluids.

3.8 Experimental Procedure

Pressure drop measurements were made for steady-state flow through each of the four drilling chokes for varying flow rates, drilling fluids, and degrees of closure.

All pressure gauges were periodically dead-weight tested to insure accuracy. Due to the number of gauges available for reading pressure, it was easily determined when any of the gauges was inaccurate. All gauges read very close if not exactly the same when functioning properly.

Initially, the appropriate valves must be opened or closed so that flow is restricted to the system depicted in Figure 3.2. This is necessary because the LSU facility is also used for well control training, as well as other research projects.

Once the flow system has been accomodated, the drilling fluid is allowed to circulate through the flow system for at least one hour. This process insures a uniform fluid throughout the system, and also allows the rheological properties of the drilling fluid to stabilize.

Additionally, it is during this time that pump factor measurements were made. Using a stop watch, the flow of fluid from the trip tanks could be measured, as well as the flow of fluid to the tanks. Using both measurements and pumping fluid at a constant rate, the following relationship will yield the pump factor:

$$\text{Pump Rate(strokes/minute)} \times \text{Minutes per Barrel Pumped} = \text{Pump Factor(strokes/bbl)} \qquad (3.1)$$

The pump factor was determined over a variety of choke positions, pump speeds, and pressures. Table 3.1 lists a sample of the data taken dealing with pump factor.

Table 3.1 - Data For and Calculated Values of Pump Factor

Pump Speed (spm)	Pressure (psi)	Barrels Pumped	Time (min:sec)	Pump Factor (stk/bbl)
73	560	5	1:47.2	26.08
34	580	4	3:03.2	25.95
50	580	4	2:06.0	26.25
28	1160	4	3:44.0	26.14
62	1150	5	2:06.3	26.11
47	1160	4	2:12.9	26.02
50	1620	4	2:04.7	25.98
32	1600	4	3:16.4	26.18
26	1600	4	4:01.3	26.14
39	700	4	2:40.4	26.07

The following fluid properties are then measured:

1) Density

2) Temperature

3) Four Fann Viscometer Readings

4) 10 Second Gel

5) 10 Minute Gel

With the drilling fluid continually circulating, the fluid properties are measured every fifteen minutes until the temperature change is less than or equal to 1°F. Once this has been achieved, pressure drop-flow rate data may be obtained.

The following procedure was used to obtain the data. Special notes clarifying the procedure will be discussed immediately afterward. It is important that these instructions are followed since they lend a consistency to the experiment.

1) The largest desired choke opening or position is set on the drilling choke. This position is then recorded.

2) The pump rate is then set to the lowest value desired. After steady-state flow conditions are reached, pressure drop and pump rate are recorded.

3) The pump rate is increased so that a significant pressure drop difference is obtained. Again, after steady-state conditions are

reached, pressure drop and pump rate are recorded.

4) Step (3) is repeated until the pressure drop nears the maximum allowable surface pressure. For this system, 1800 psi was the maximum allowable.

5) The choke is then adjusted to the next largest choke setting desired. Having recorded this choke position, steps (2) through (4) are repeated.

6) Drilling fluid properties are measured every hour once the data-taking process is started.

It is desired, for reasons of consistency, to obtain data in an"increasing-pressure" sequence. This requires the flow rate to be increased as data is taken for a given choke position. Also, choke positions are adjusted to smaller orifice sizes in keeping with the "increasing-pressure" policy. However, if the desired choke position is passed during closure, the choke should be opened fully, and the desired position once again sought. This will allow the choke position to be set using closing hydraulic pressure, only, and thus insure that flow line pressure will not change the choke position.

To determine a "significant" pressure drop difference, it is necessary to determine the maximum pressure drop that can be obtained for a given choke position. Of course, should this exceed the 1800 psi limit, 1800 psi would be used as the maximum. Once the maximum pressure drop is determined, the pump rate is dropped to zero, and not increased unitl pressure in the system has likewise dropped to zero.

It was decided that the number of data points required per choke position should be five. Following this criteria, then, a "significant" pressure drop would be defined as one-fifth the maximum obtainable pressure drop. The pump rate would then be increased until the pressure read from the gauges was "significant." For larger orifice sizes, a significant pressure drop difference could be as little as 30 psi; whereas, for smaller orifice sizes, this value could be as high as 350 psi.

To determine exactly which choke positions could be termed "desired," it was necessary to experiment with water as the drilling fluid on each choke. Since a series of curves depicting flow rate versus pressure drop was expected it was hoped that the choke positions could be chosen so that the curves were, to some extent, equidistant from each other. Thus, an initial investigation as to what the choke positions should be yielded those which were then used throughout the study. Of course, these choke positions varied for each drilling choke.

A knowledge of the exact position of the travelling member of the choke elements was deemed necessary for the success of the experiment, and, therefore, in addition to the choke position indicator supplied with the drilling chokes, a mechanical means of measuring position was developed.

For the Cameron Manual Choke, this was not necessary. Since the choke position indicator is a mechanical type of device, the choke could be positioned where desired quite easily. However, the rotation of the handwheel was measured, and, recalling that the piston travelled one-eighth of an inch for every 360° turn of the handwheel, Figure 3.12 was developed.

Because pneumatic actuators were used to give a choke position on the control consoles, the operating heads of each of the remaining chokes were examined to determine if measurement of the travelling element could be made. Upon investigation into the head of the Cameron High-Pressure Remote Choke, a piston rod was found that relayed choke position to the actuator. By placing a clamp on this rod, a surface was established where upon a dial indicator (Figure 3.1) stem could be placed to determine actual gate travel. The relationship between actual piston travel and choke panel position indicator is given in Figure 3.14. Total gate

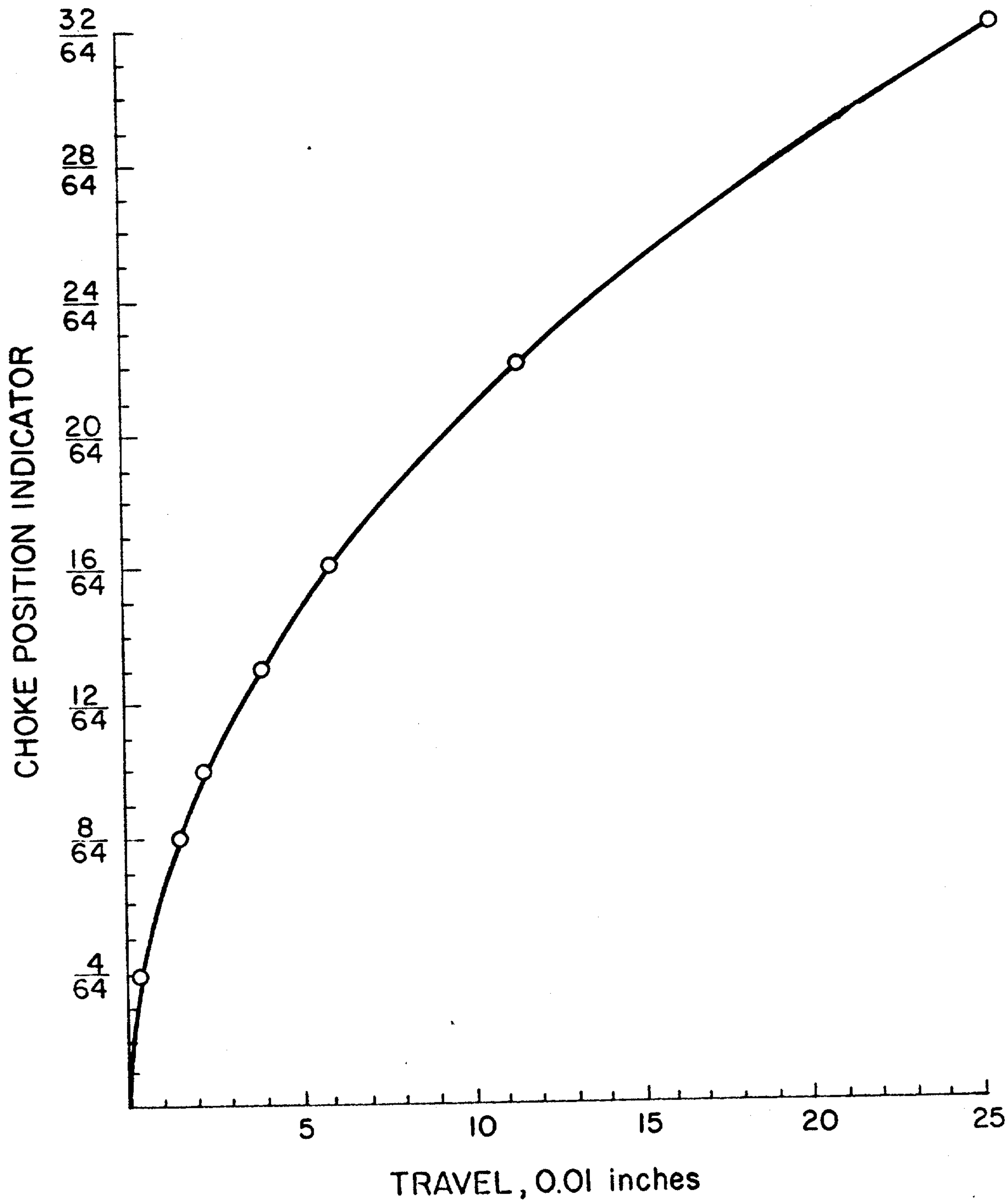
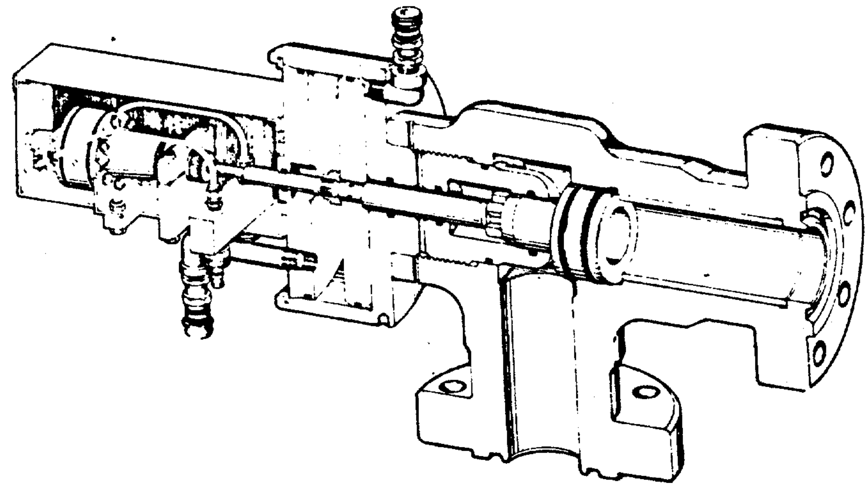


Figure 3.12 - Piston Travel As A Function of Choke Position Indicator For the Cameron Manual Choke



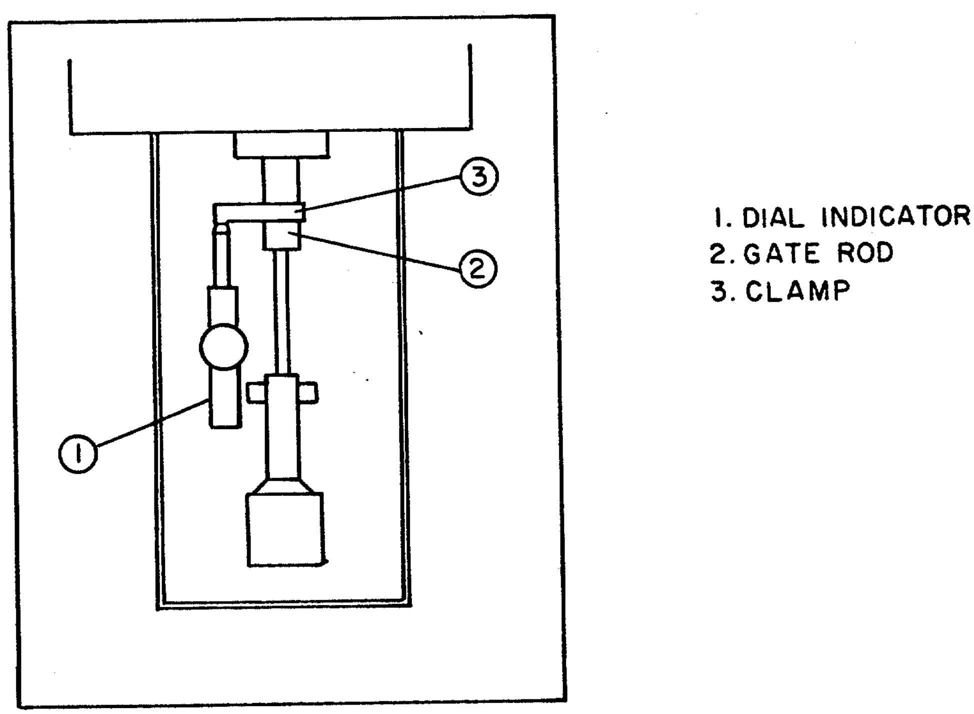


Figure 3.13 - Cameron High Pressure-Remote Adjustable Choke (After Cameron)

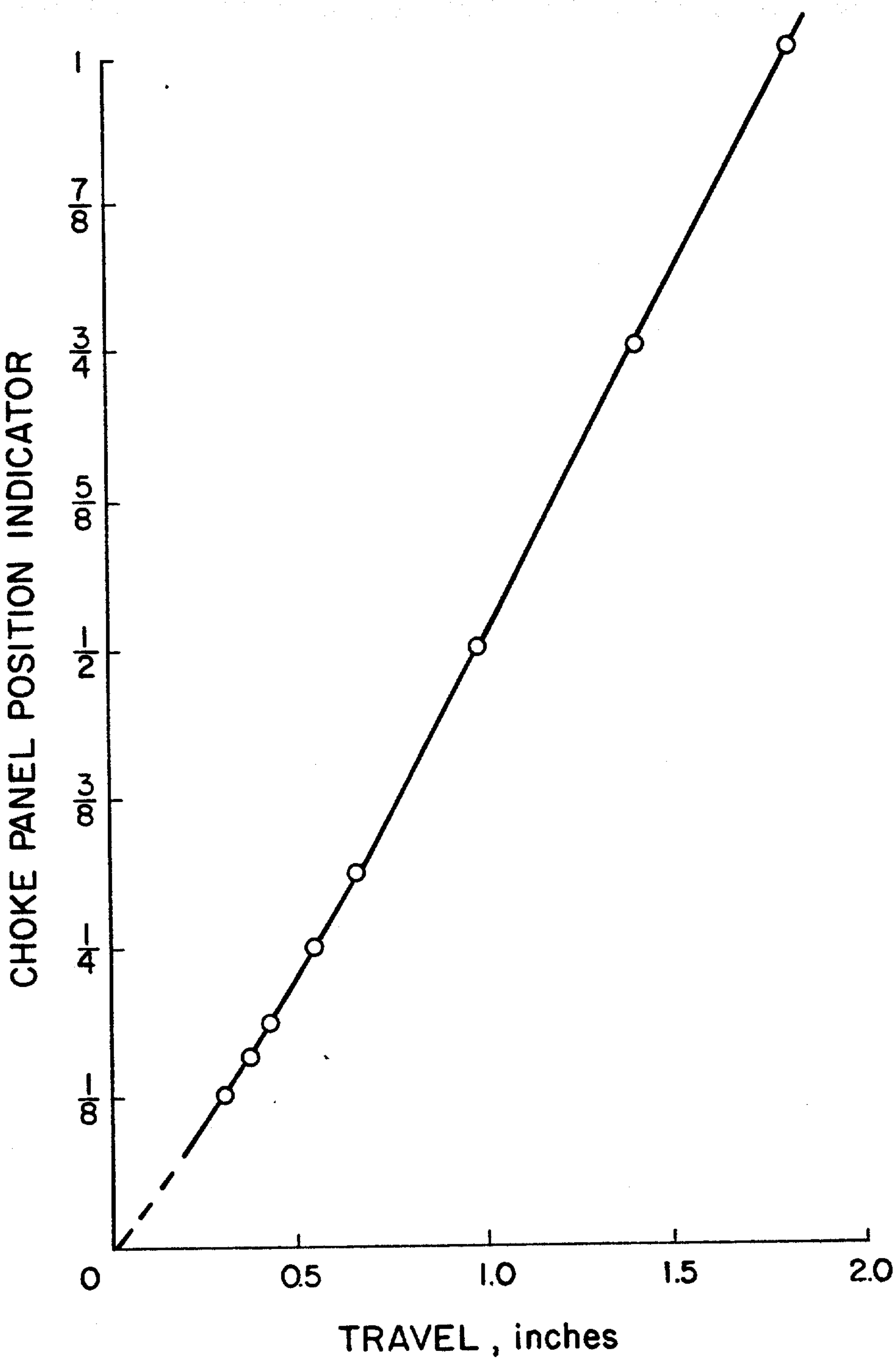


Figure 3.14 - Piston Travel As A Function of Choke Panel Position Indicator For The Cameron High Pressure Remote Choke

travel was found to be 1.841 inches.

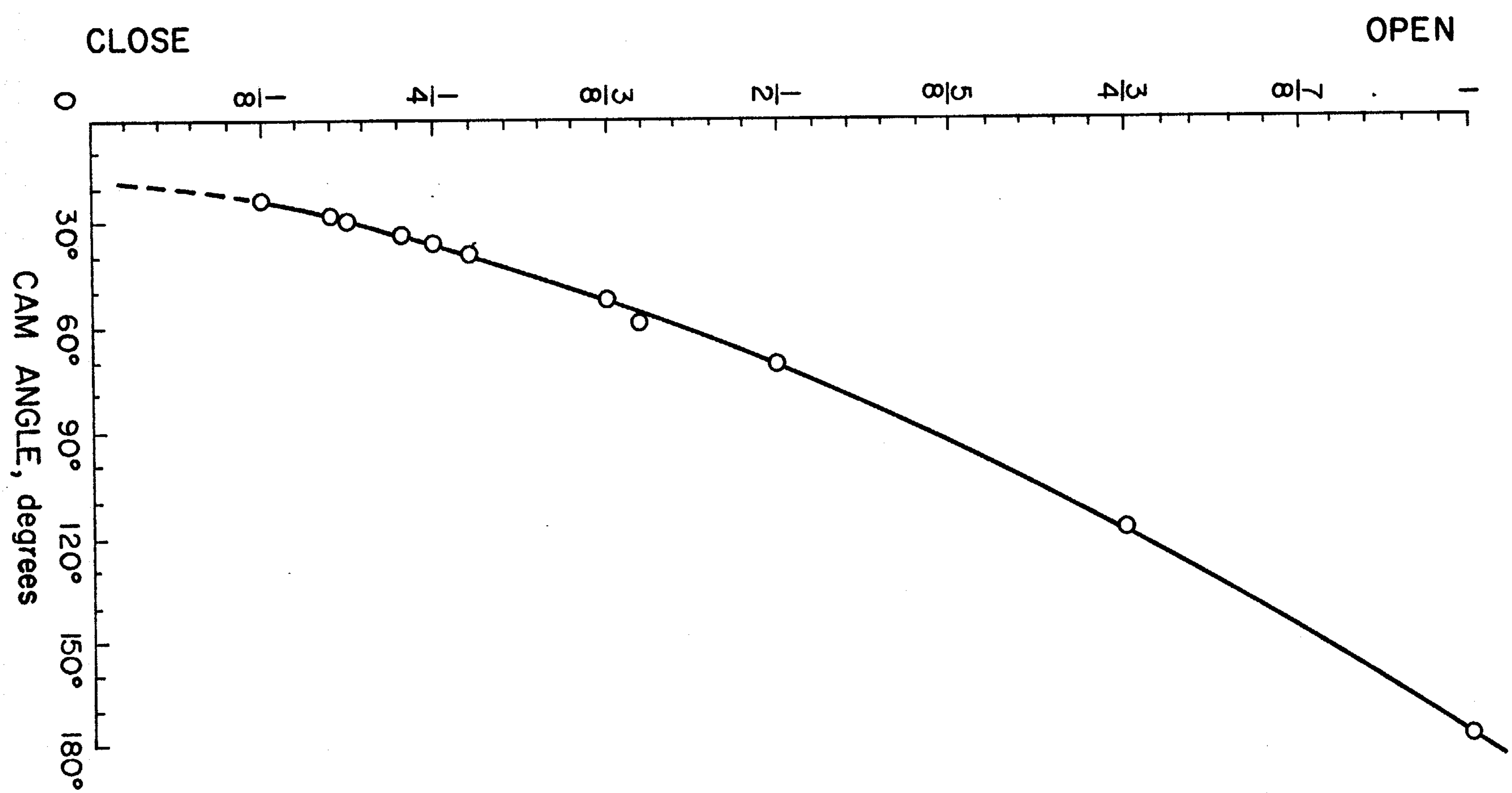
The head of the Swaco Super Choke displayed a cam (See inset Figure 3.7) which, upon further experimentation, was found to rotate one-hundred and eighty degrees when the choke was adjusted from fully open to fully closed. Resting on the cam is a positioning wheel which is held in place by a follower rod. The follower rod allows the pneumatic activator to relay choke posi- to the choke control console. The point at which the position wheel and the cam touch gives the choke position or angle through which the travelling element has rotated. Figure 3.15 displays Cam Angle as a function of Choke Panel Position Indicator.

Attempts to determine a mechanical means of measuring travel of the choke element for the Patterson Adjustable Choke failed, and, therefore, it was decided to take data using the position indicator on the choke console.

The flow rate supplied by the pump was determined using the pump factor and the pump speed. Having measured the pump factor in strokes per barrel and the pump speed in strokes per minute, the flow rate in gallons per minute is obtained using:

$$q = \frac{\text{Pump Rate (stk/min)}}{\text{Pump Factor (stk/bbl)}} \times 42 \ \frac{\text{gallons}}{\text{bbl}} \qquad (3.2)$$

Figure 3.15 - Cam Angle As A Function Of Choke Position Indicator
For The Swaco Super Choke



CHAPTER IV

EXPERIMENTAL RESULTS

Following the procedure described in Chapter III, and using the experimental apparatus depicted in Figure 3.2, frictional pressure losses across each of the four different drilling chokes were recorded as a function of choke position, fluid properties, and flow rate under steady-state conditions. From this data (Tables A-1 to A-26), graphical representations were developed to depict the pressure drop-flow rate characteristics of each drilling choke as both orifice size and fluid type were varied. These representations comprise Figures 4.1 to 4.18. Table 4.1 summarizes the fluid properties.

A malfunction in the hydraulic pump on the Patterson Choke caused the termination of the data-taking process in regards to this choke. Although the choke remained certainly capable of performing its intended functions, it was not possible to maintain a given choke position without continually adjusting the choke for each data point. Due to the fact that it was impossible to return to the same choke position and maintain that position during the time required to observe pressure drops for five flow rate changes, it was decided to continue the experiment without the use of the Patterson Adjustable Choke.

An immediate observation that could be made regarding all of the drilling chokes concerns the choke position when a pressure drop initially takes place. It appears that frictional pressure loss across the chokes is negligible until the chokes are approximately half-closed. There is also no concern for back pressure on the choke manifold due to the orientation of the flow conduit from the manifold to the trip tanks (See Figure 3.2), since pressure drops were zero with the choke completely open regardless of the flow rate used. The pressure drop can, therefore, be simply read as the upstream pressure, the same pressure monitored by the choke panel gauges.

In order to determine the effects of varying fluid properties, six different drilling fluids were used. Although, as shown in Table 4.1, seven drilling fluids are listed, further investigation will prove that fluid number 2 and fluid number 3 are extremely similar. However, since the viscosity did change somewhat during experimentation, different identification numbers were used. Drilling fluid number 1 is tap water. Drilling fluid numbers 2 and 3 are low viscosity clay-water muds. Drilling fluid numbers 4 and 5 are higher viscosity clay-water muds. The desired viscosity was obtained by adding bentonite clay to the drilling fluid in the

Drill Fluid Number	Temp, °F	Density, lb/gal	Fann Viscometer 600 rpm	300 rpm	200 rpm	100 rpm	10-sec Gel lb/100 ft^2	10-min Gel lb/100 ft^2	Plastic Viscosity cp	Yield Point lb/100 ft^2
1	70	8.33	2.0	1.0	0.67	0.33	0.0	0.0	1.0	0.0
2	85	8.60	6.0	3.0	1.5	0.5	0.0	0.0	3.0	0.0
3	115	8.60	4.0	2.0	1.0	0.0	0.0	0.0	2.0	0.0
4	110	8.60	43.0	28.0	23.5	16.0	11.0	32.0	15.0	13.0
5	105	8.60	80.0	57.0	48.0	37.0	30.0	58.0	23.0	34.0
6	84	10.70	83.0	55.0	44.0	29.5	12.0	41.0	28.0	27.0
7	82	12.05	62.0	40.0	31.0	20.5	6.0	24.0	22.0	18.0

Table 4.1 - Summary of Fluid Properties

metering tanks.

To weight up the drilling fluid, barite was added into the metering tanks, resulting in drilling fluids 6 and 7.

So that the effects of fluid viscosity on the flow characteristics of the drilling choke could be studied three fluids of equal density but differing viscosity were employed. It was, once again, immediately obvious that the viscosity of the fluid affected the pressure drop across the chokes, since, as expected, for the same choke position, flow rate, and fluid density, pressure drop for the various viscosities was unequal. In this study, the significance of viscosity change and the applicability of the existing calculation techniques for describing the flow through the drilling chokes was investigated.

Valve coefficients are used in the valve industry to characterize pressure losses through valves and fittings. Since it was shown in the Literature Review that these coefficients could be of use to this study, the values of C_v were determined from the curves (Figures 4.1-4.18) so that comparisons between flow rates could be made. Tables B-1 to B-16 include the calculated values of C_v, along with the respective pressures, flow rates, and fluid types.

It can be observed directly from the tables that changes in viscosity certainly affect the computed value of C_v. The tables also show that for drilling fluids of similar viscosity, the valve coefficient can be used successfully to reduce the data to a single trend line. Therefore, if a viscosity term could be included in the valve coefficient equation, this equation could very well describe the pressure drop-flow rate characteristics of any given choke position for any drilling fluid.

Plots of the valve coefficient as a funtion of actual choke position are shown in Figures 4.19 to 4.21. As can be seen from these figures, the behavior of the choke is quite similar regardless of the drilling fluid used, and a "band" or range of values of C_v may well describe choke behavior at any given choke position. The curves represented in Figures 4.19 and 4.20 reveal a shape much like that of Figure 3.6b, published by Cameron Iron Works.[7] The difference in the numerical values of C_v is attributed to a great extent to the wear of the choke elements through use and differences in the calibrations of the choke position indicator.

Because of the values of C_v for a given choke position being so close from one fluid to the next, it is felt that the viscosity of the fluid enjoys but a minor significance when considering the behavior of the choke. The choke may well be represented by an average value of C_v for a given choke position, with a correction factor or chart which would alter the value of C_v for varying rheological properties. The development of such a chart or factor, however, is beyond the scope of this work.

As seen in Figure 3.9, Swaco publishes an Equivalent Bean Size Chart.[17] The bean size or equivalent diameter open to flow is plotted against the choke position indicator. In an effort to reproduce this chart, the area open to flow was traced and planimetered, at the various choke positions indicated. This was accomplished by using two Swaco choke elements (see Figure 3.7), which were rotated through the appropriate angle for a given choke position (as indicated by the choke panel). Table 4.2 lists the choke indicator position, actual cam angle, planimetered area, and calculated equivalent bean size. To calculate the equivalent bean size, the following equation may be used:

$$\text{Bean Size} = \sqrt{\frac{4}{\pi} \times (\text{Planimetered Area})} \qquad (4.1)$$

Figure 4.22 represents the "Equivalent Bean Size Chart" developed during this study. It is interesting to note that the curve of Figure 4.22 agrees with the Swaco curve, except at the very upper end where the choke is 90 to 100% open. This is not felt to be significant.

TABLE 4.2

DATA FOR AND CALCULATED VALUES OF

EQUIVALENT BEAN SIZE - SWACO CHOKE

Choke Panel Position Indicator	CAM Angle (degrees)	Planimetered Area (inches^2)	Equivalent Bean Size (inches)
1/8	24°	0	0
7/40	28°	0.05	0.25
3/16	30°	0.08	0.32
9/40	33°	0.10	0.36
1/4	37°	0.15	0.44
11/40	40°	0.30	0.62
3/8	53°	0.35	0.67
2/5	60°	0.50	0.80
1/2	73°	0.70	0.94
1	180°	2.35	1.73

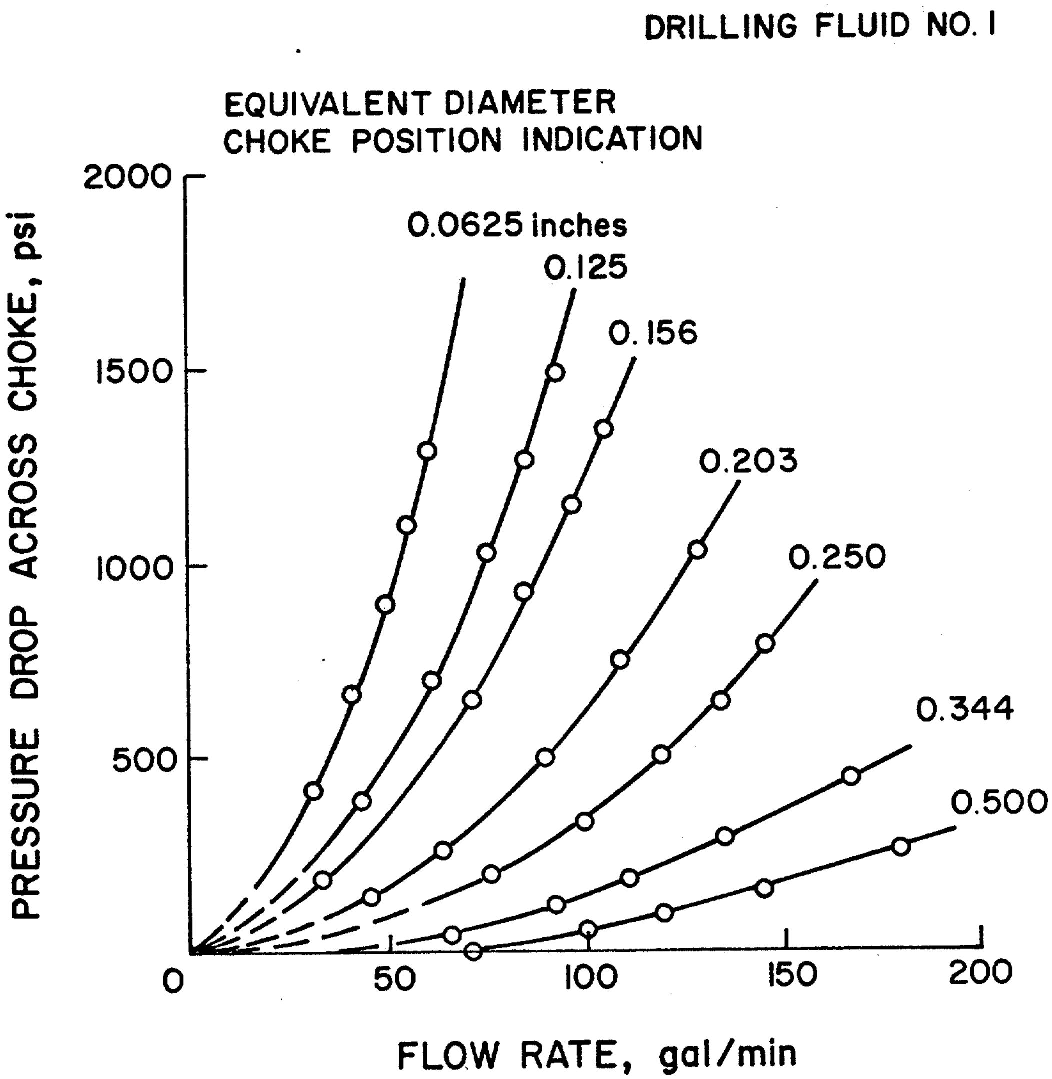


Figure 4.1 - Pressure Drop Through The Cameron Manual Choke For Varying Positions of Closure

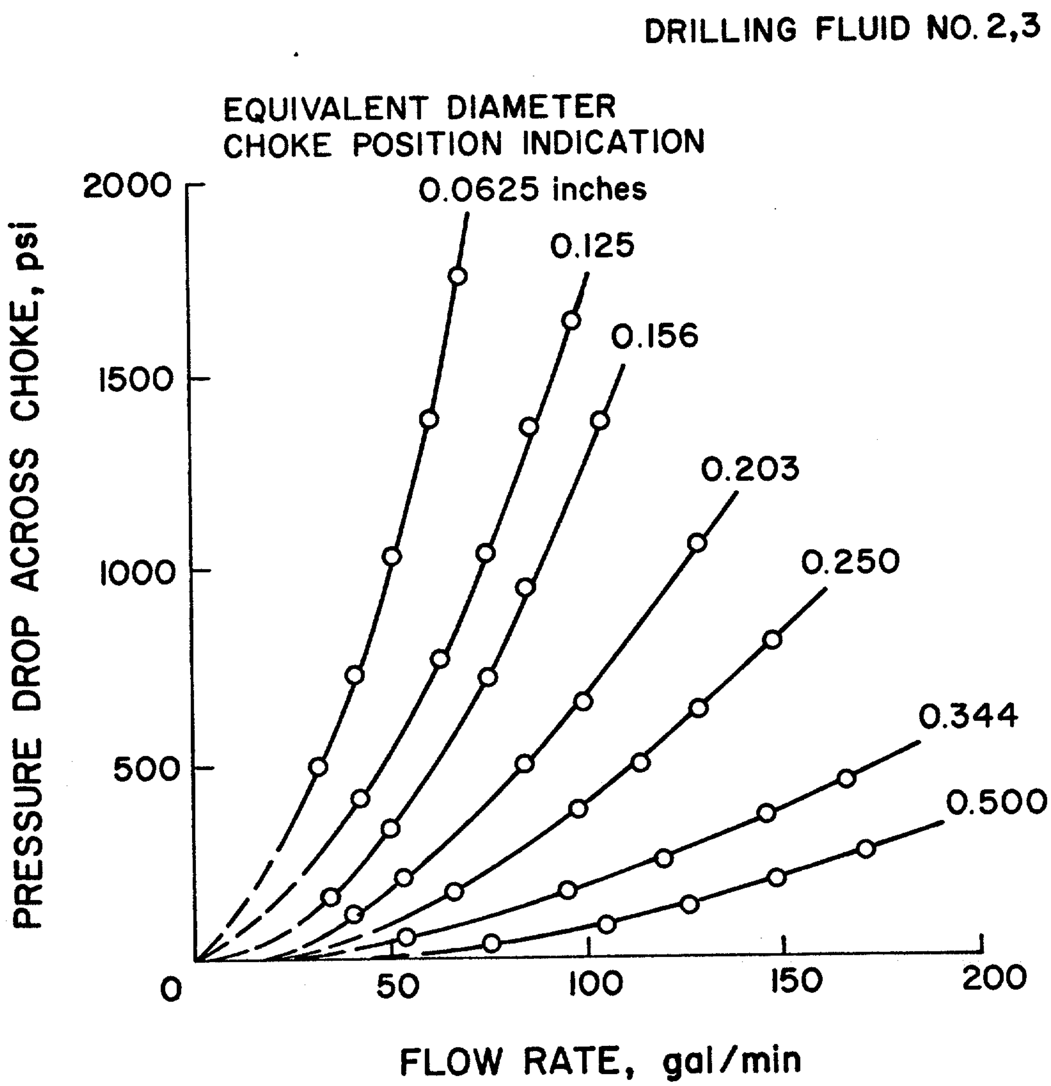


Figure 4.2 - Pressure Drop Through The Cameron Manual Choke For Varying Positions of Closure

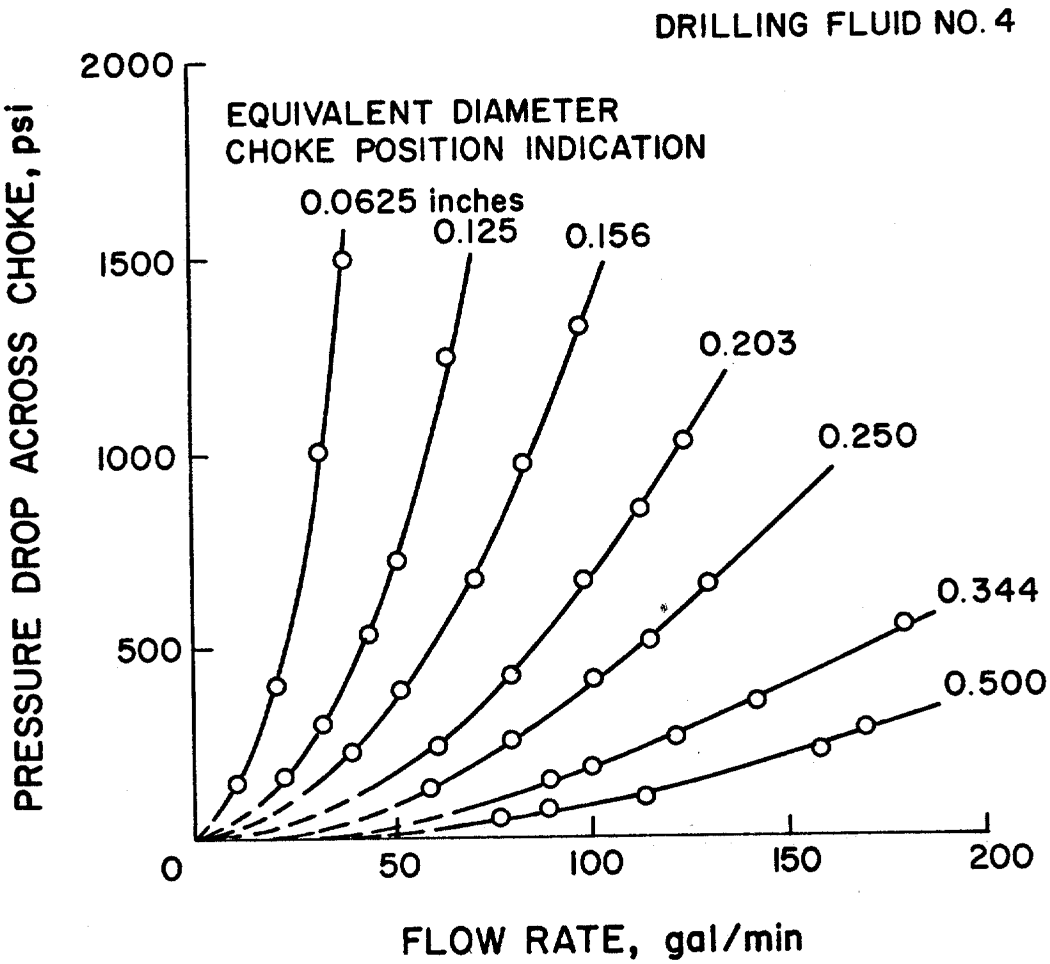


Figure 4.3 - Pressure Drop Through The Cameron Manual Choke For Varying Positions of Closure

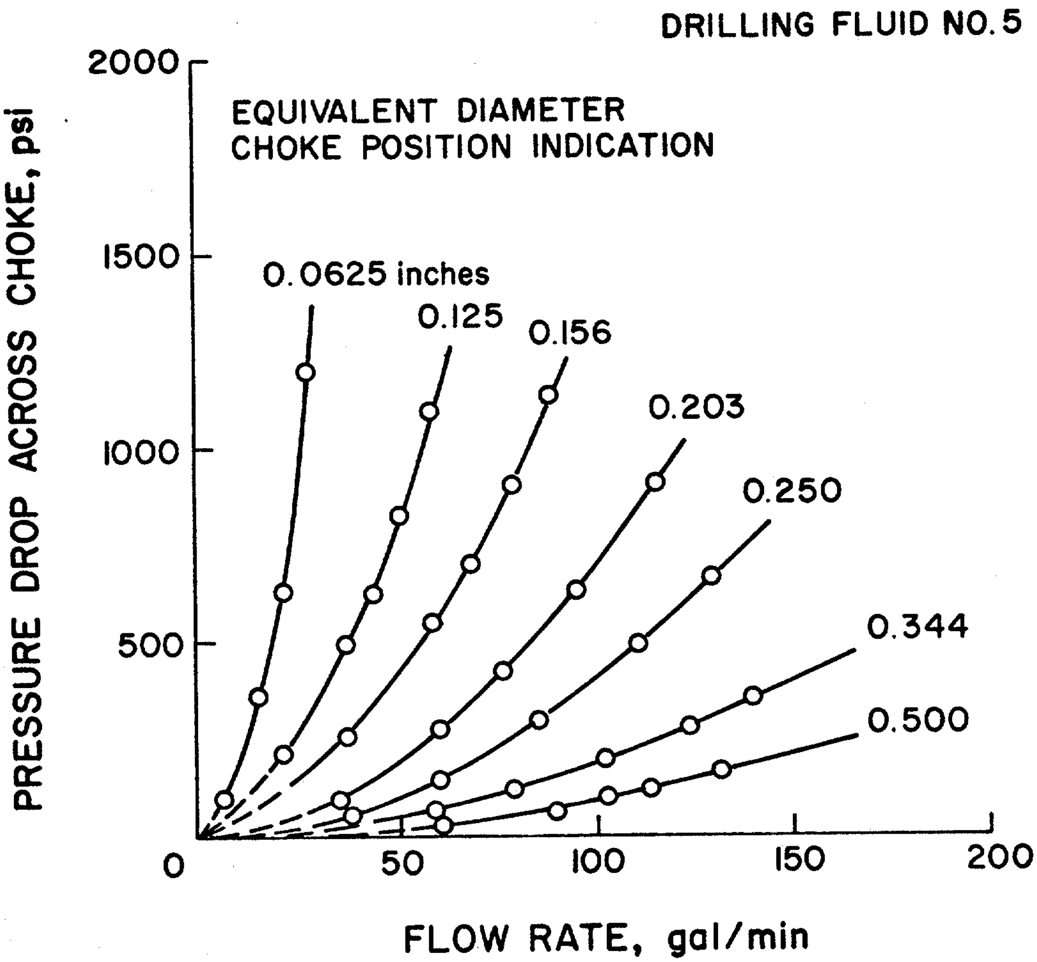


Figure 4.4 - Pressure Drop Through The Cameron Manual Choke For Varying Positions of Closure

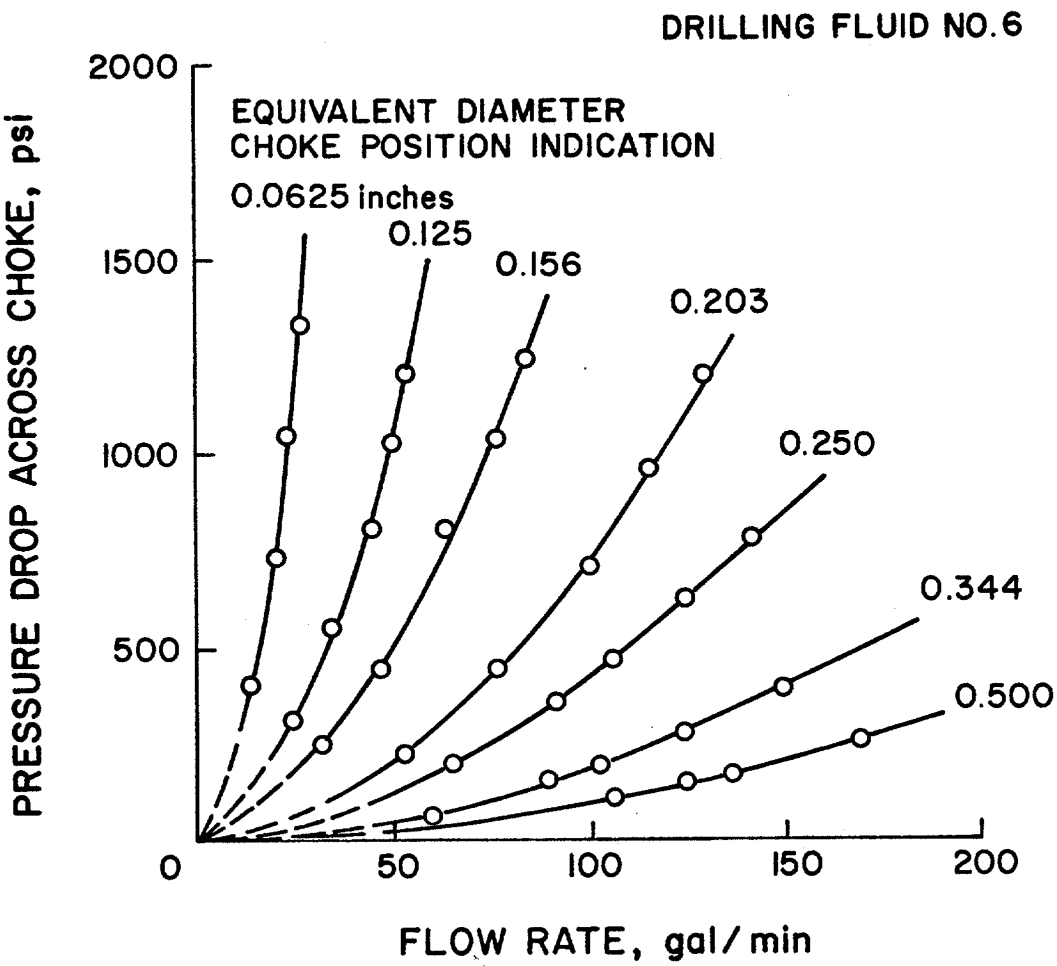


Figure 4.5 - Pressure Drop Through The Cameron Manual Choke For Varying Positions of Closure

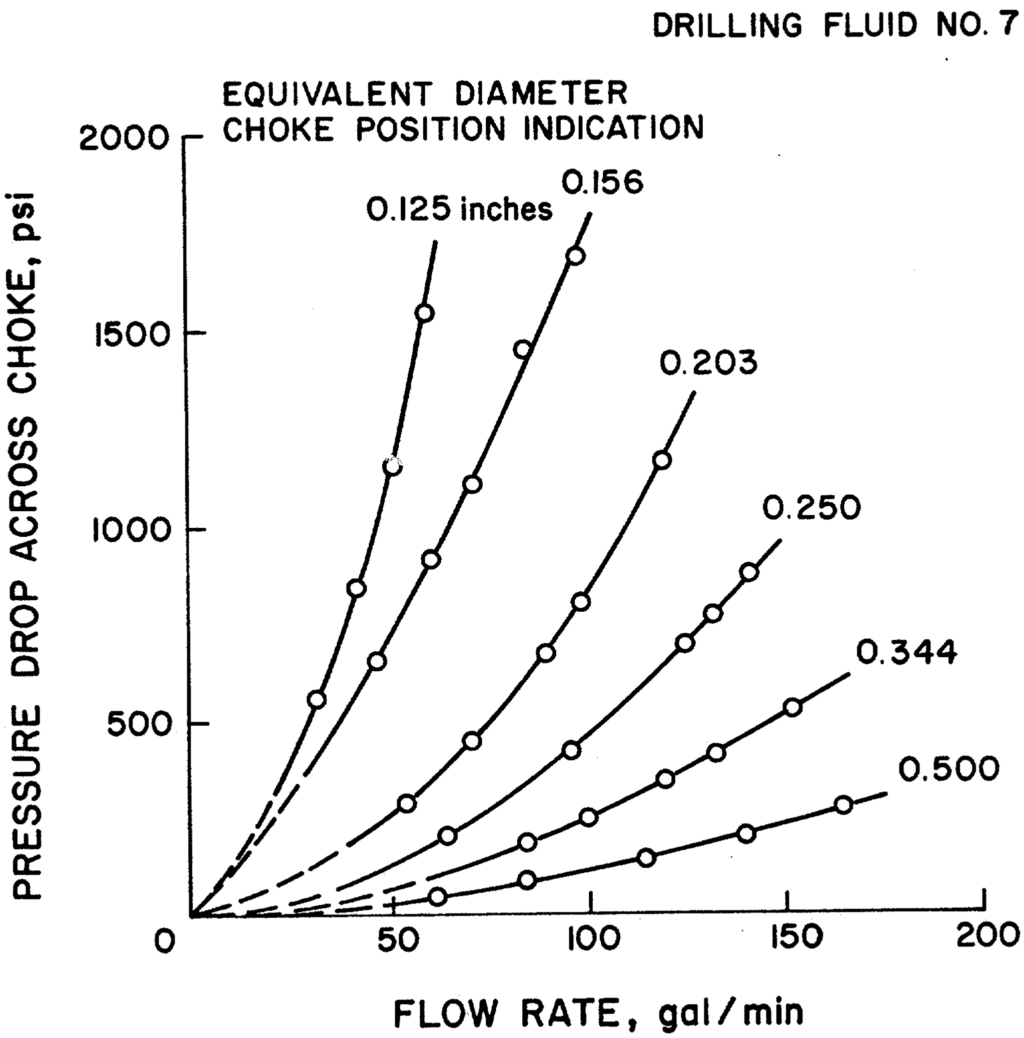


Figure 4.6 - Pressure Drop Through The Cameron Manual Choke For Varying Positions of Choke

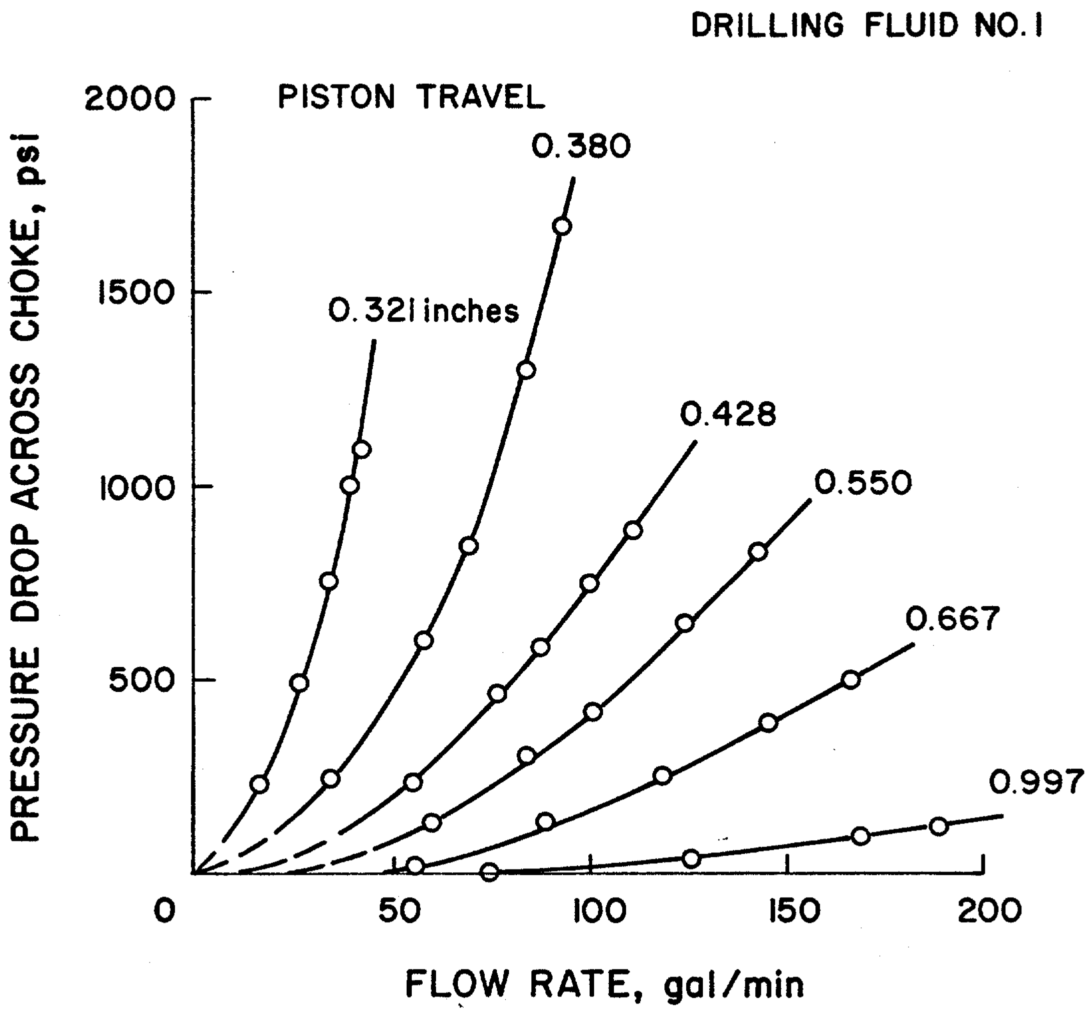


Figure 4.7 - Pressure Drop Through The Cameron High Pressure Remote Choke For Varying Positions of Closure

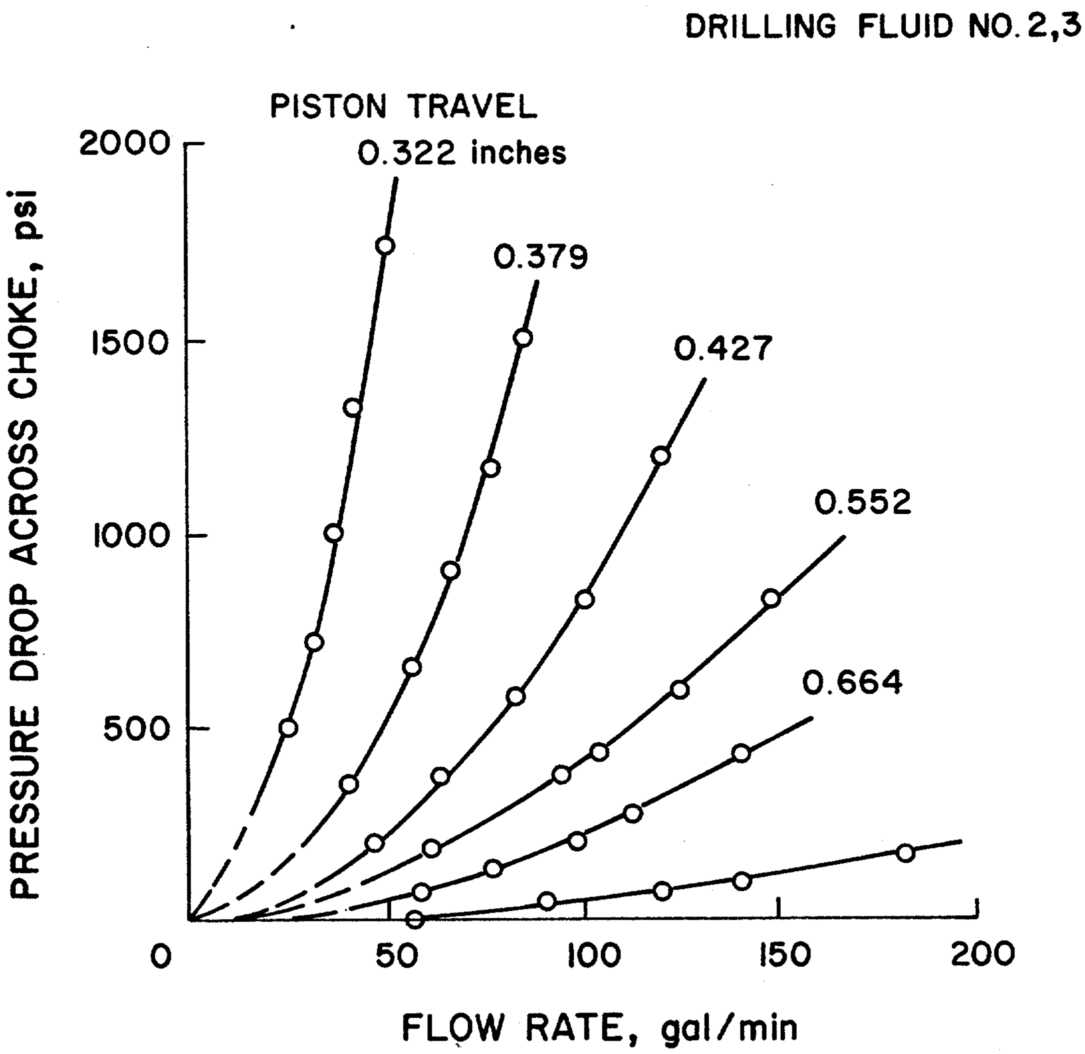


Figure 4.8 - Pressure Drop Through Cameron High Pressure Remote Choke For Varying Positions of Closure

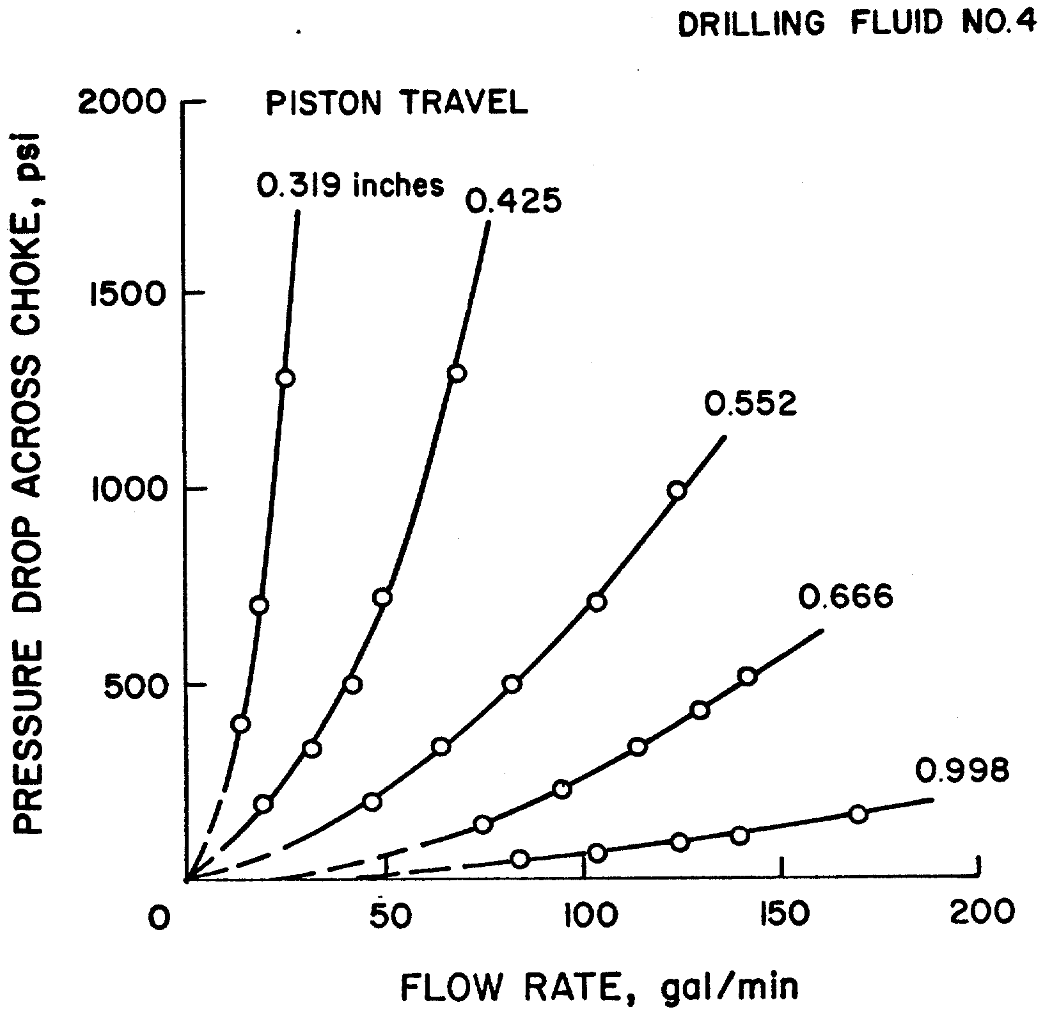


Figure 4.9 - Pressure Drop Through Cameron High Pressure Remote Choke For Varying Positions of Closure

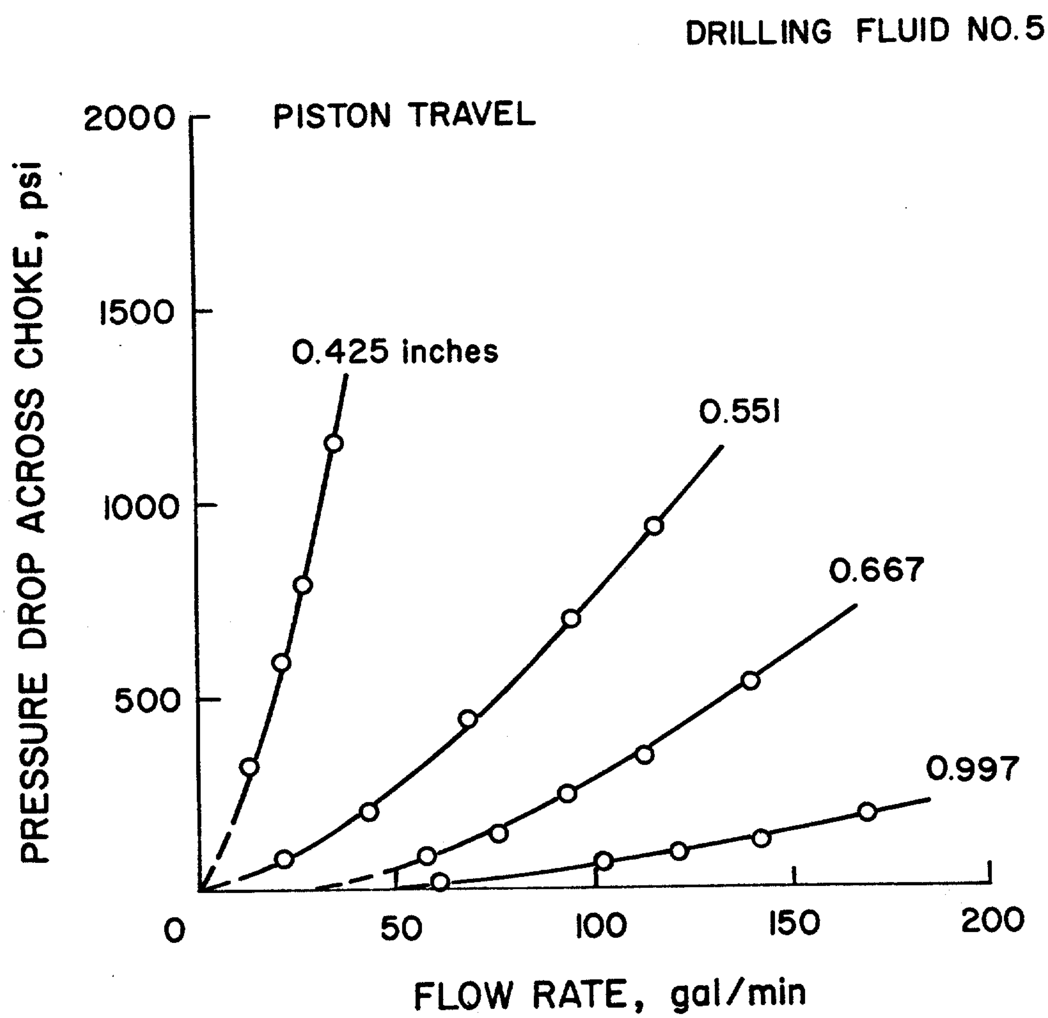


Figure 4.10 - Pressure Drop Through Cameron High Pressure Remote Choke For Varying Positions of Closure

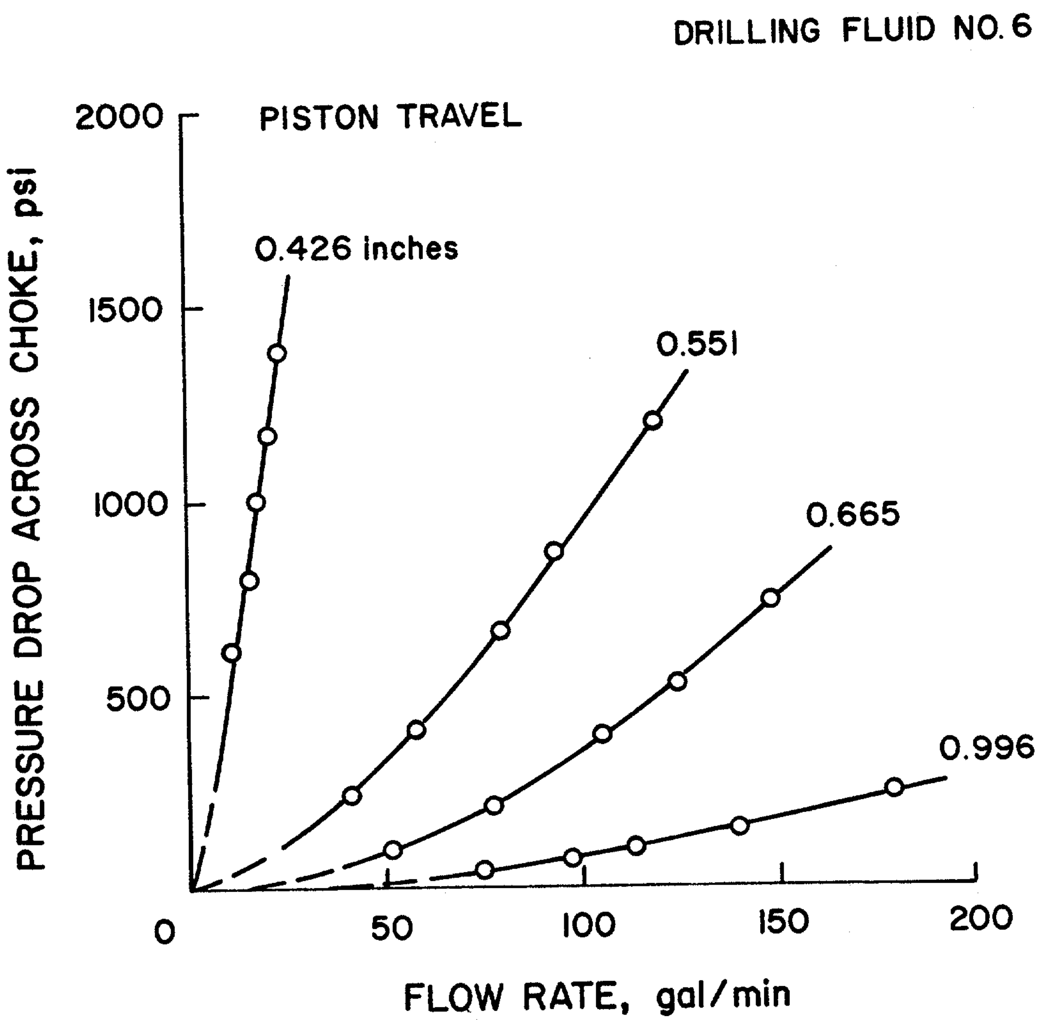


Figure 4.11 - Pressure Drop Through Cameron High Pressure Remote Choke For Varying Positions of Closure

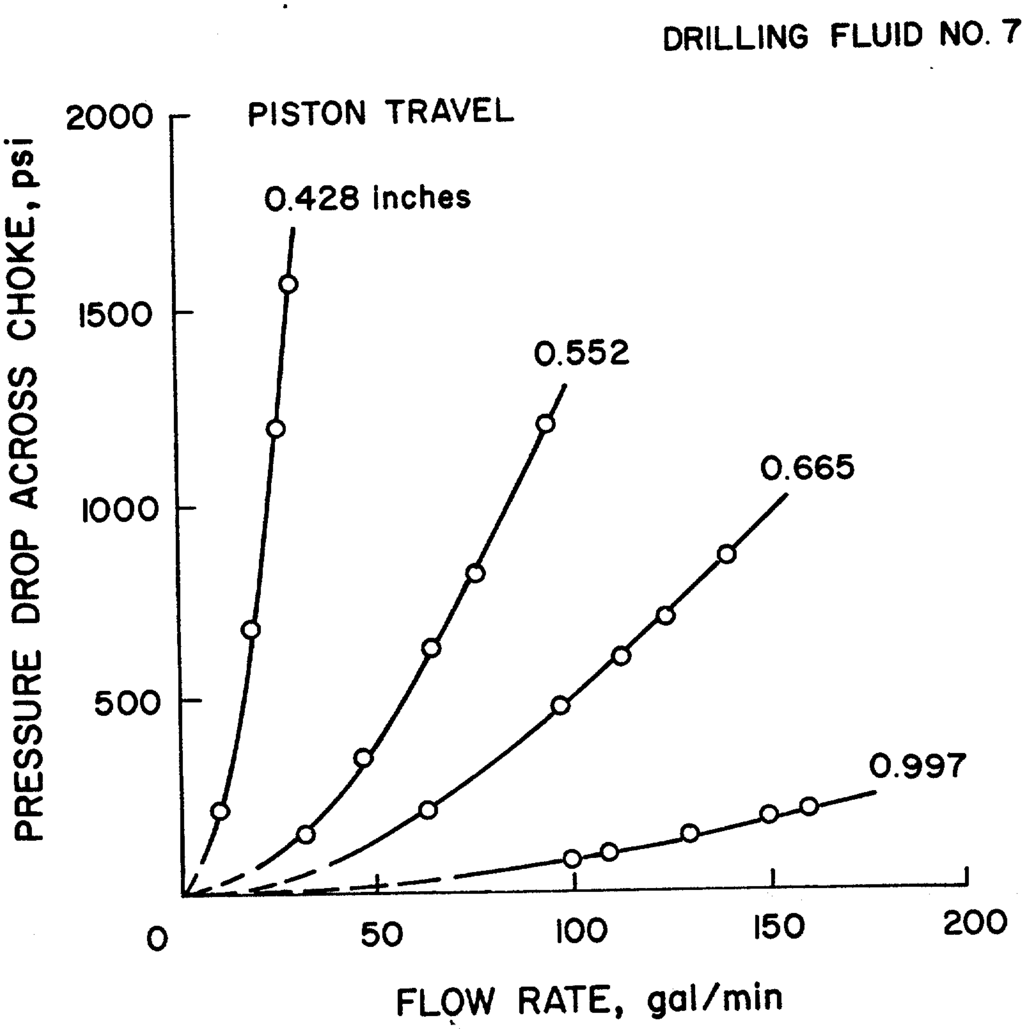


Figure 4.12 - Pressure Drop Through The Cameron High Pressure Remote Choke For Varying Positions of Closure

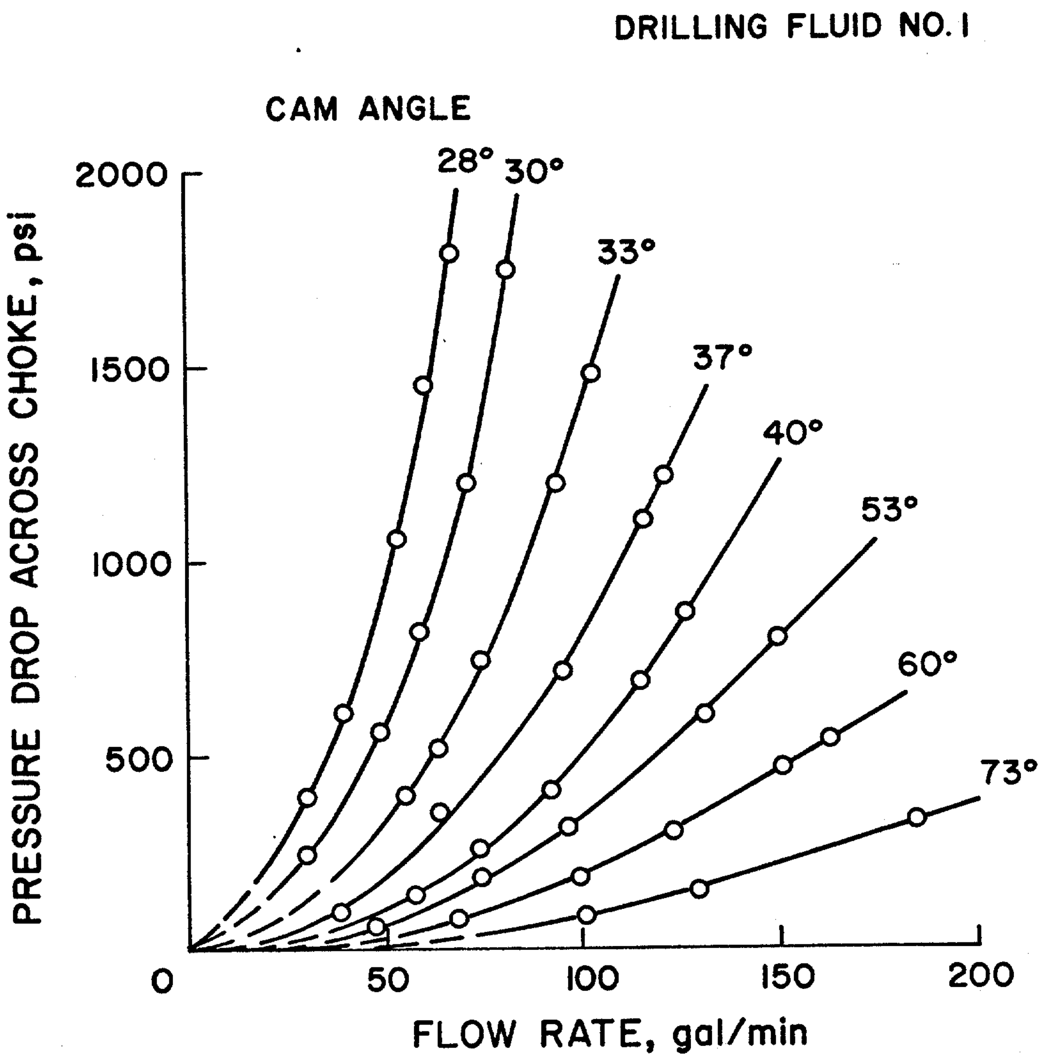


Figure 4.13 - Pressure Drop Through The Swaco Super Choke For Varying Positions of Closure

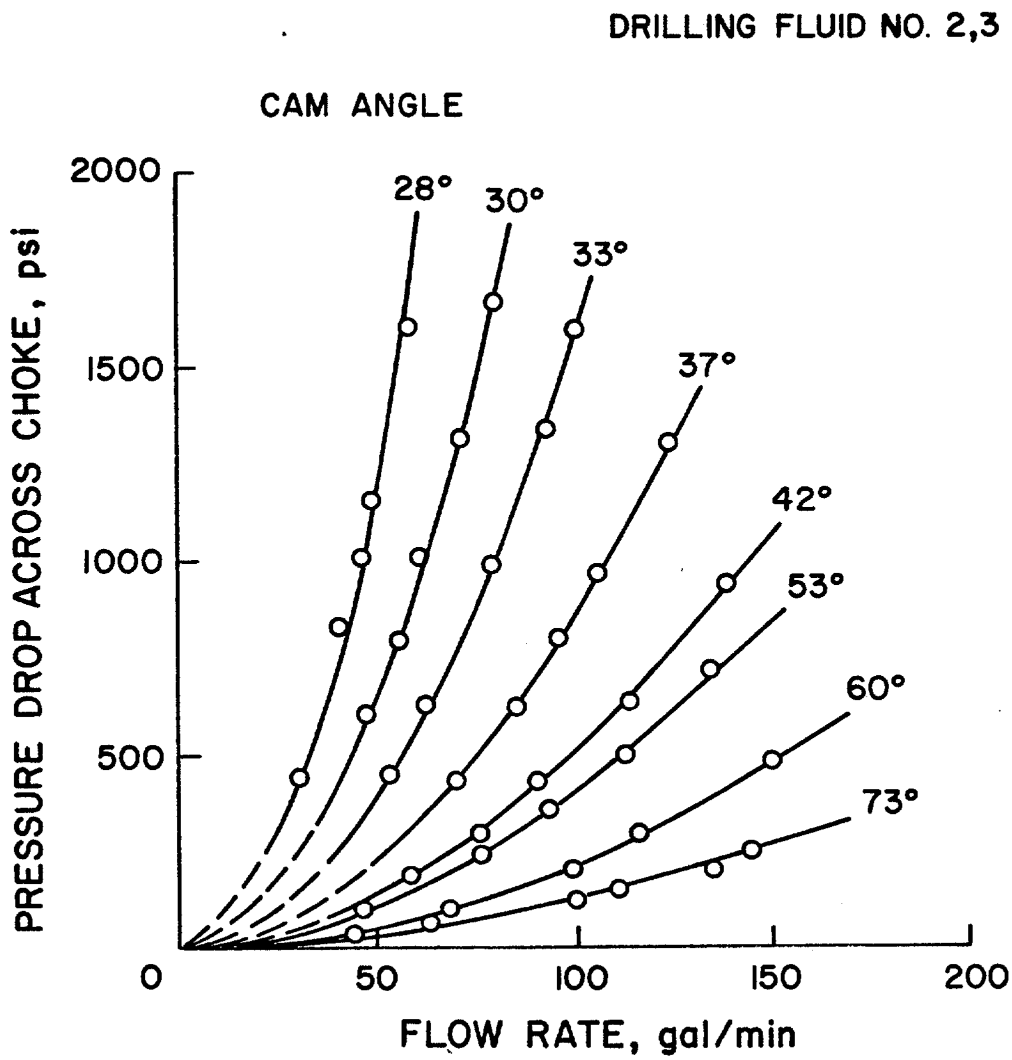


Figure 4.14 - Pressure Drop Through The Swaco Super Choke For Varying Positions of Closure

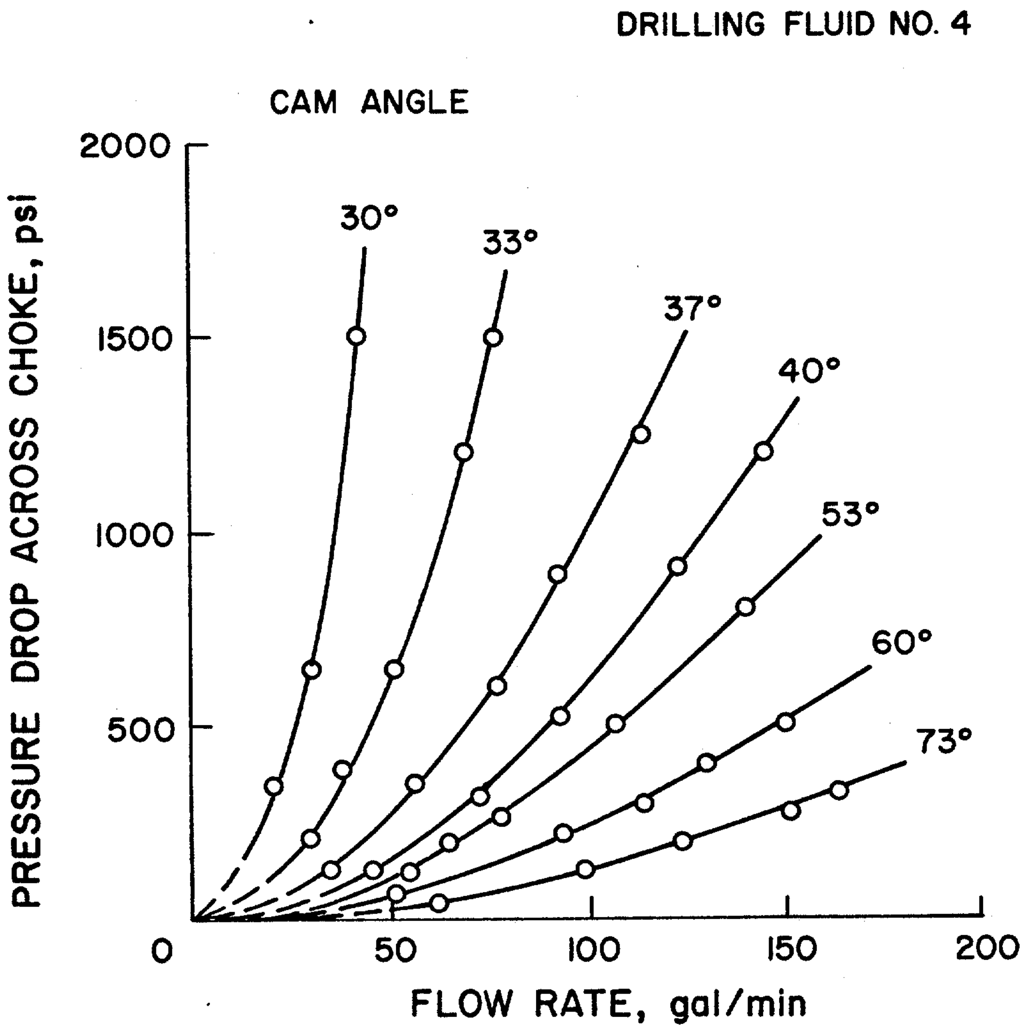


Figure 4.15 - Pressure Drop Through The Swaco Super Choke For Varying Positions of Closure

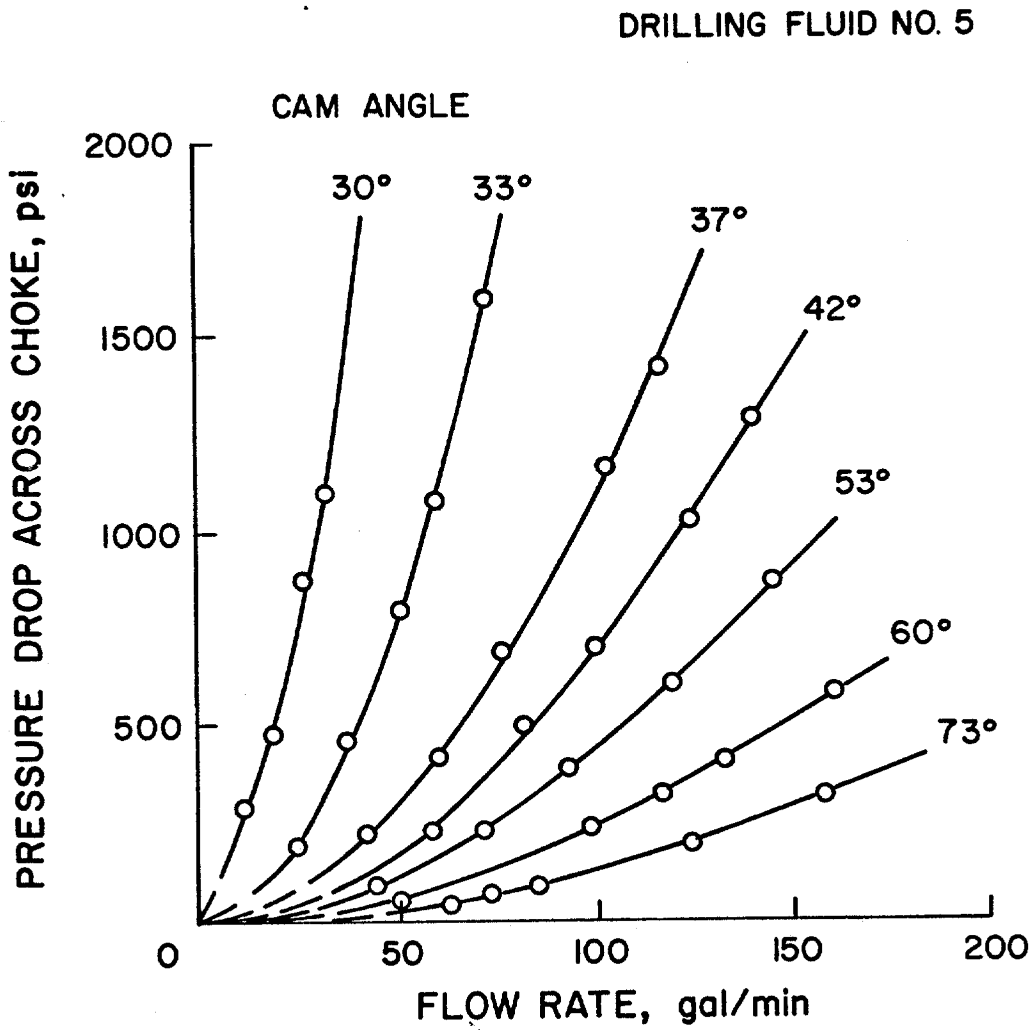


Figure 4.16 - Pressure Drop Through The Swaco Super Choke For Varying Positions of Closure

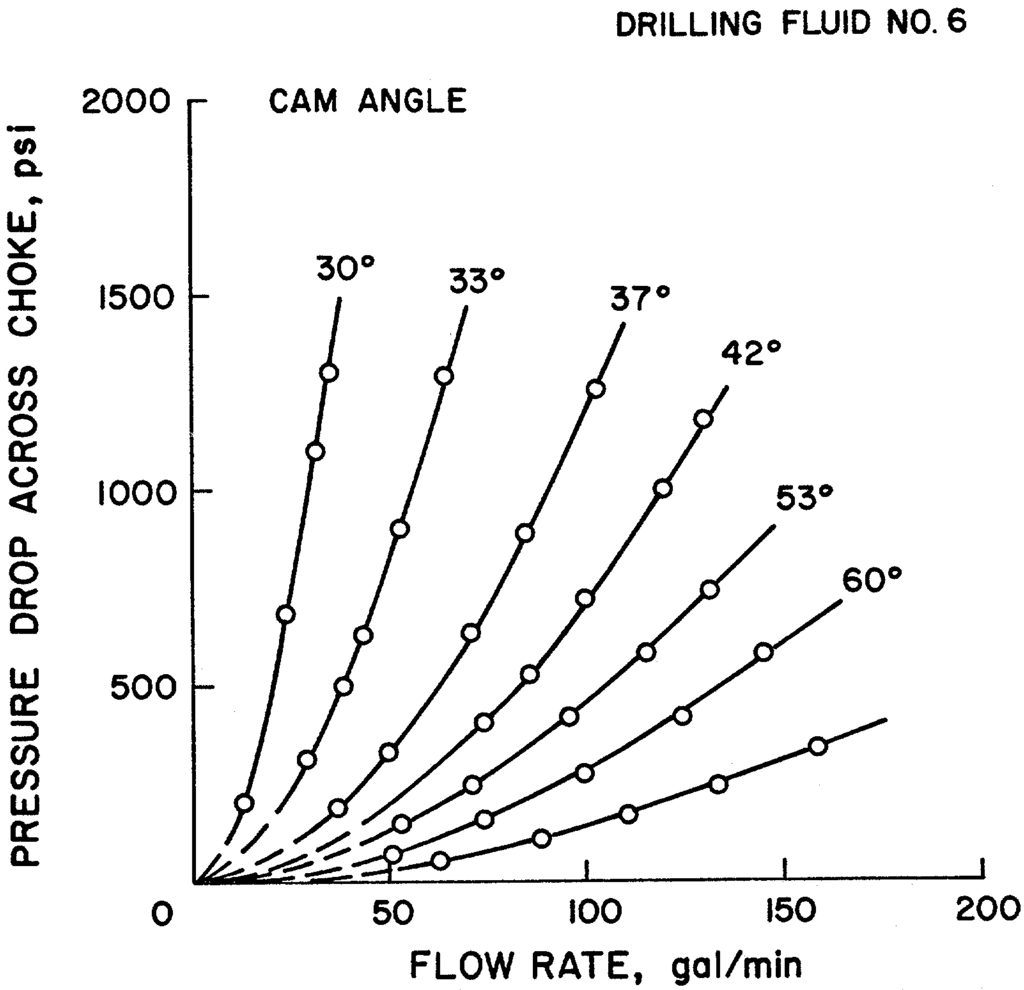


Figure 4.17 - Pressure Drop Through The Swaco Super Choke For Varying Positions of Closure

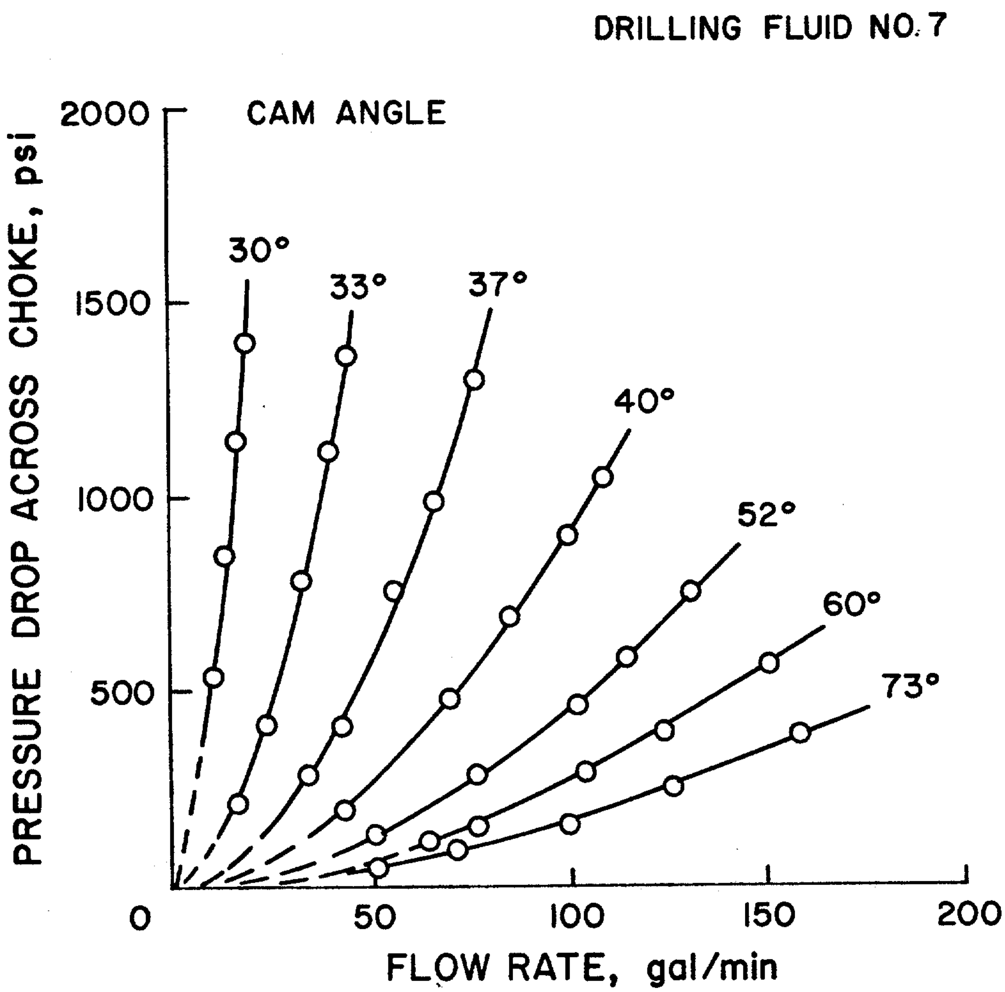


Figure 4.18 - Pressure Drop Through The Swaco Super Choke For Varying Positions of Closure

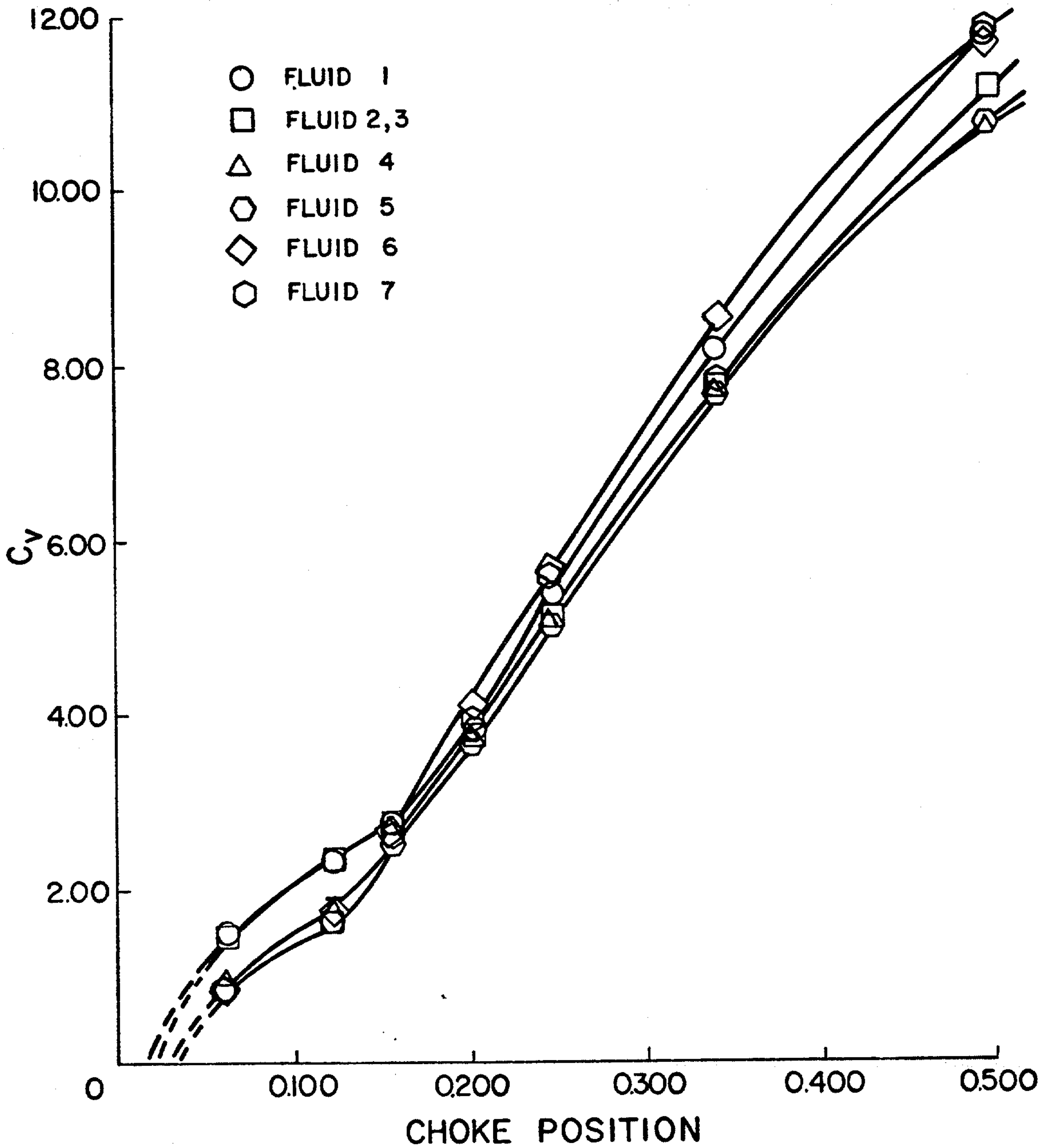


Figure 4.19 - C_V As A Function of Choke Position For Varying Fluids Using Cameron Manual Choke

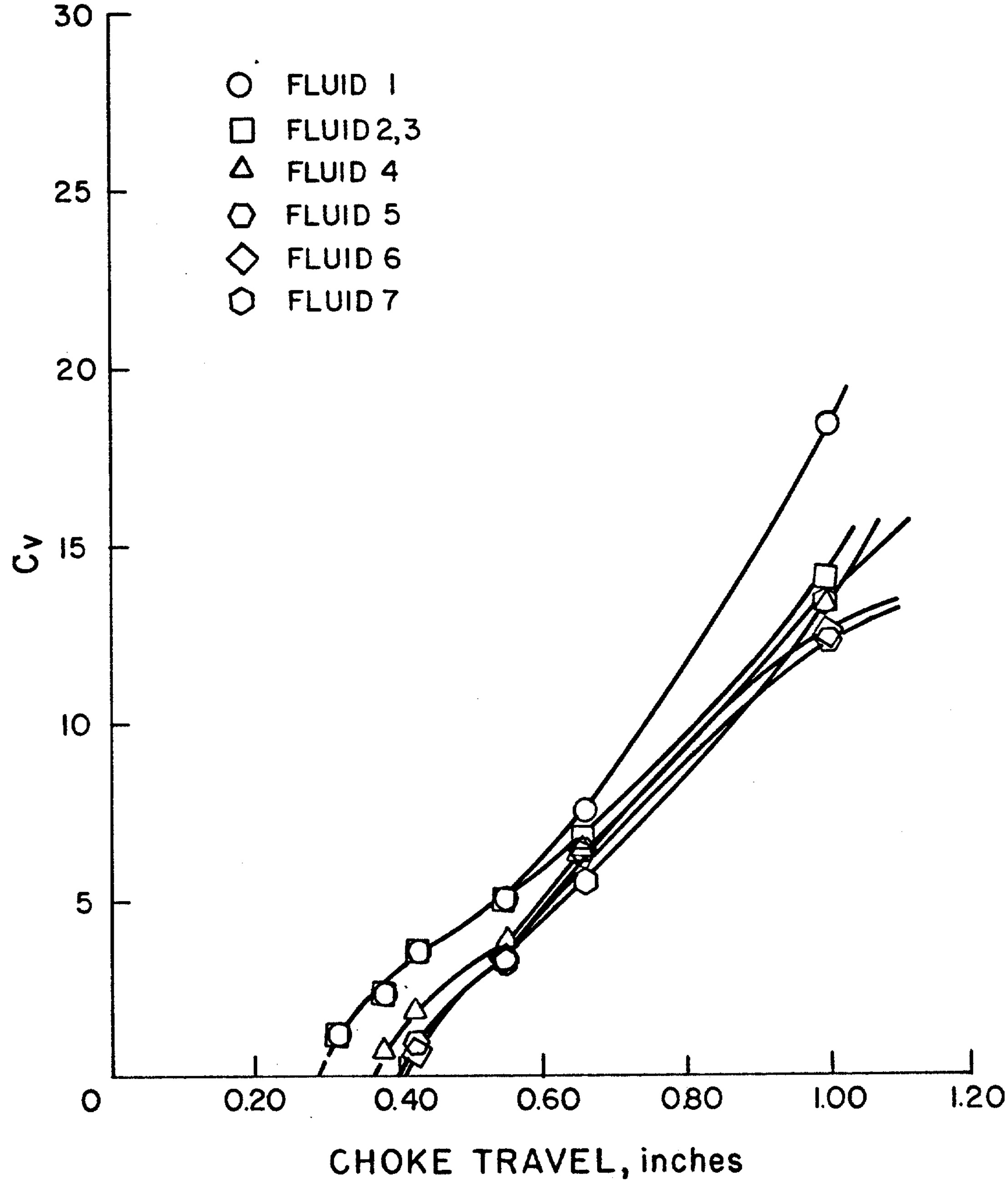


Figure 4.20 - C_v As A Function of Choke Position For Varying Fluids Using Cameron High Pressure Remote Choke

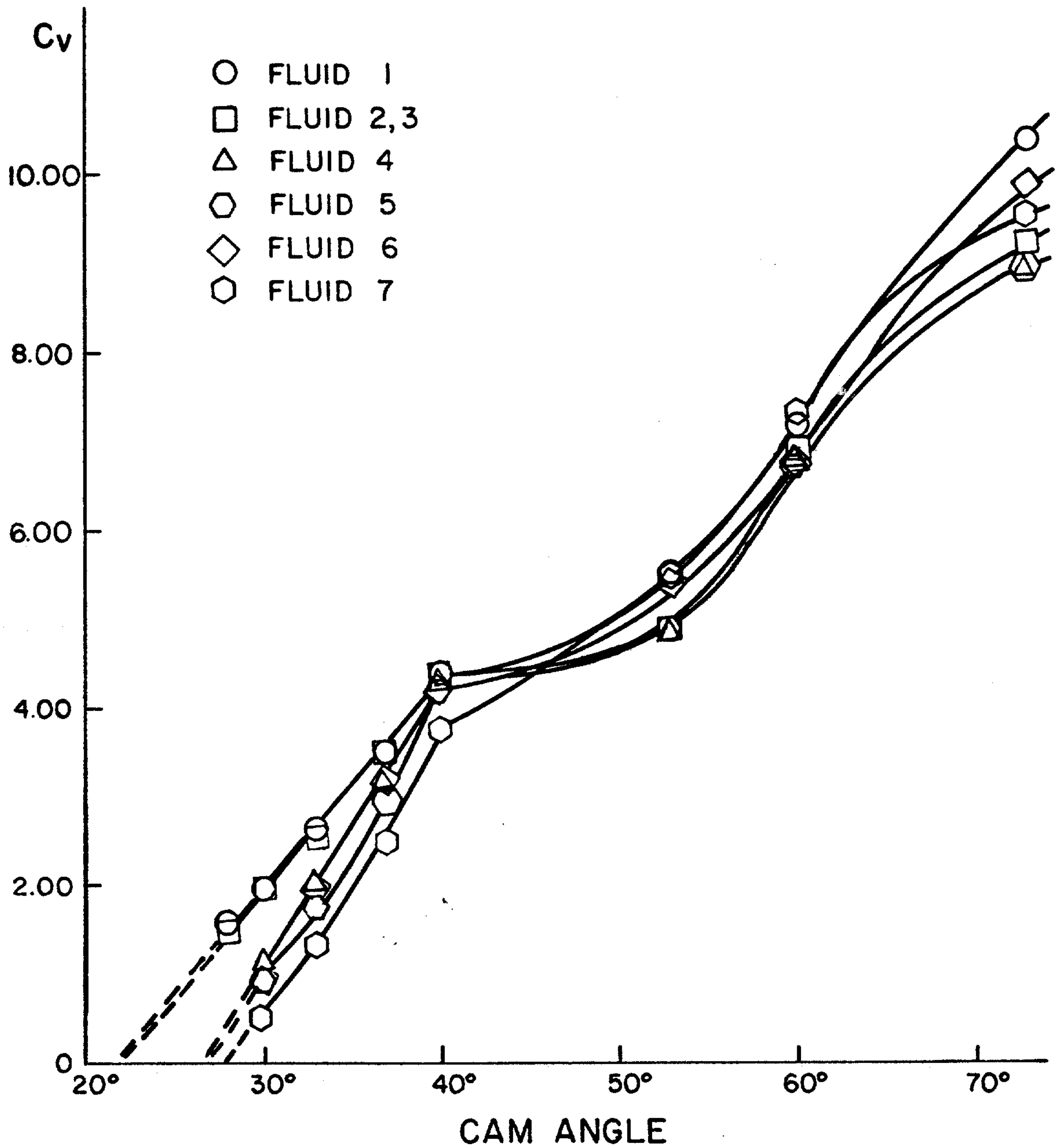


Figure 4.21 - C_v As A Function of Choke Position For Varying Fluids Using Swaco Super Choke

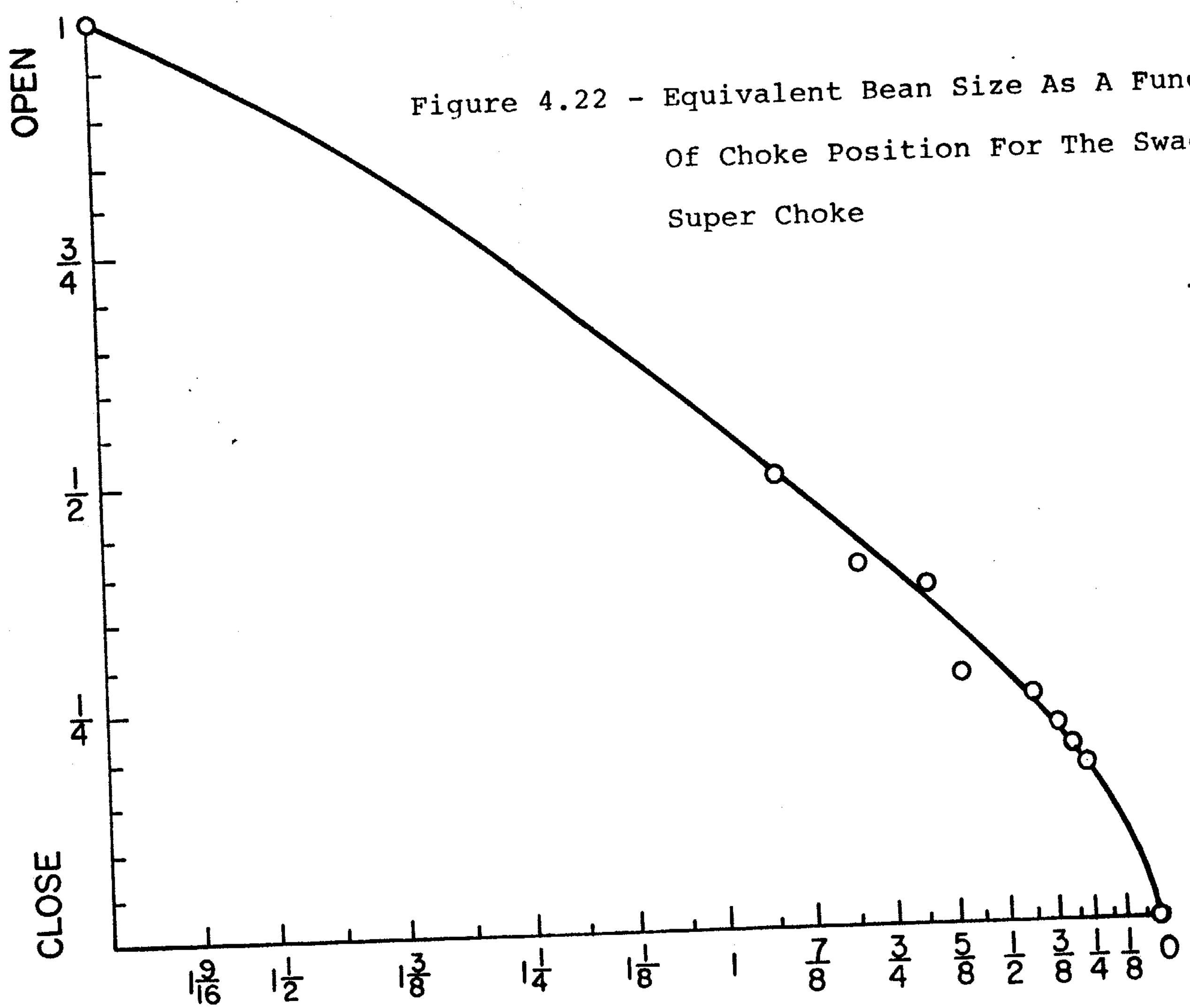


Figure 4.22 - Equivalent Bean Size As A Function Of Choke Position For The Swaco Super Choke

CHAPTER V

CONCLUSIONS AND RECOMMENDATIONS

Based on the experimental results of this study, the following conclusions can be drawn:

1) The restriction of flow through the four commercially available drilling chokes used in this study is small, if not negligible, until the chokes are approximately 50% closed.
2) The effects of fluid viscosity on the flow rate characteristics of the drilling chokes is of minor significance when considering fluids such as those used in common drilling applications.
3) The valve coefficient C_v, as it is defined, is a valid technique for defining an approximate drilling choke behavior.
4) A small improvement in the accuracy of the valve coefficient equation for predicting drilling choke behavior could be obtained through the introduction of an appropriate viscosity term.

As previously stated, this study is but a part of a large, on-going research effort to develop improved techniques of well control, especially as it is applied to deep-sea drilling. In regard to the continuation of the research project, the following recommendations are made:

1) This data along with similar data should be evaluated to determine either a "choke coefficient equation" or some "correction correlations" (if C_v is to be used) to more accurately describe the effect viscosity has on quantitative values of pressure drop. This would be necessary from a purely mathematical standpoint if a model was to be developed.

2) Compressible flow of single, two, and three phases should be used to further advance the choke modelling.

3) The use of C_v in the development of a computer model to simulate actual behavior of a commercial drilling choke is reasonably accurate if single-phase, incompressible fluids are used. However, it is expected that behavior will change when compressible fluids are used, and C_v, as defined, will become inappropriate. The further development of multi-phase flow correlations under drilling-type conditions using drilling chokes is required if the electronic simulator is to be used and properly modelled for the training of drilling personnel.

14. Doyle, R. S.: "Pressure Drop - Flow Rate Characteristics of a Spherical Type Blowout Preventer During Closure," M.S. Thesis, Louisiana State University, Baton Rouge, 1981.

15. Patterson Rental Tools, Inc.: Personal Communications.

16. Patterson Rental Tools, Inc: "Patterson Adjustable Choke," Houma, Louisiana.

17. Dresser, Industries: "Swaco Super Choke," Bulletin No. E-53031-BC, Houston, Texas.

APPENDIX

Table A-1 - Experimental Pressure Drop Data

For The Cameron Manual Choke

Choke Position	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
32/64	1	44	71	0
		63	101	60
		74	119	100
		90	145	160
		111	179	260
22/64	1	41	66	40
		57	92	120
		69	111	180
		84	135	280
		104	167	440
16/64	1	47	76	200
		62	100	340
		74	119	500
		83	134	640
		91	146	780
13/64	1	28	45	140
		39	63	260
		56	90	500
		68	109	760
		80	129	1040
10/64	1	21	34	190
		45	72	650

Table A-2 - Experimental Pressure Drop Data

For The Cameron Manual Choke

Choke Position	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
10/64	1	53	85	920
		60	97	1150
		66	106	1350
8/64	1	27	43	380
		38	61	700
		47	76	1030
		53	85	1270
		58	93	1490
4/64	1	19	31	420
		26	42	670
		31	50	900
		34	55	1100
		38	61	1290
32/64	2	45	72	30
		66	106	80
		78	126	130
		92	148	200
		106	171	270
22/64	2	33	53	60
		59	95	170
		74	119	250
		91	146	370
		104	167	460

Table A-3 - Experimental Pressure Drop Data

For The Cameron Manual Choke

Choke Position	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
16/64	2	41	66	170
		61	98	380
		71	114	500
		81	130	640
		92	148	820
12/64	3	25	40	120
		33	53	210
		53	85	500
		62	100	660
		80	129	1070
10/64	3	22	35	160
		32	51	340
		47	76	720
		55	86	960
		65	105	1380
8/64	3	27	43	420
		39	63	770
		47	76	1050
		54	87	1370
		61	98	1640
4/64	3	20	32	500
		26	42	740

Table A-4 - Experimental Pressure Drop Data

For The Cameron Manual Choke

Choke Position	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
4/64	3	32	51	1030
		38	61	1390
		43	69	1760
32/64	4	47	76	60
		55	89	80
		70	113	110
		98	158	230
		105	169	290
22/64	4	55	89	150
		62	100	180
		75	121	270
		88	142	360
		111	179	550
16/64	4	36	58	130
		49	79	270
		63	101	420
		70	113	510
		81	130	650
13/64	4	38	61	250
		50	80	420
		61	98	680
		70	113	860
		77	124	1020

Table A-5 - Experimental Pressure Drop Data

For The Cameron Manual Choke

Choke Position	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
10/64	4	24	39	230
		32	51	390
		44	71	670
		52	84	970
		61	98	1320
8/64	4	14	23	170
		20	32	300
		27	43	530
		32	51	720
		40	64	1350
4/64	4	6	10	150
		12	19	400
		20	32	1000
		24	39	1500
32/64	5	38	61	30
		55	89	70
		64	103	100
		70	113	120
		82	132	170
22/64	5	36	58	70
		49	79	120
		64	103	200

Table A-6 - Experimental Pressure Drop Data

For The Cameron Manual Choke

Choke Position	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
22/64	5	77	124	280
		87	140	360
16/64	5	23	37	60
		37	60	150
		53	85	300
		69	111	490
		80	129	670
13/64	5	22	35	100
		37	60	280
		47	76	420
		59	95	630
		72	116	910
10/64	5	23	37	270
		36	58	550
		42	68	700
		49	79	910
		55	89	1130
8/64	5	13	21	220
		23	37	500
		27	43	620
		31	50	820
		36	58	1100

Table A- 7 - Experimental Pressure Drop Data

For The Cameron Manual Choke

Choke Position	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
4/64	5	4	6	100
		9	14	370
		13	21	640
		17	27	1200
32/64	6	66	106	110
		77	124	150
		85	137	170
		105	169	260
22/64	6	37	60	70
		55	89	160
		64	103	200
		77	124	280
		93	150	390
16/64	6	40	64	200
		57	92	360
		66	106	470
		77	124	620
		85	142	780
13/64	6	33	53	230
		47	76	450
		62	100	710
		72	116	960

Table A- 8 - Experimental Pressure Drop Data

For The Cameron Manual Choke

Choke Position	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
13/64	6	81	130	1200
10/64	6	20	32	250
		29	47	440
		39	63	800
		47	76	1040
		52	84	1250
8/64	6	15	24	310
		21	34	550
		28	45	800
		31	50	1020
		33	53	1200
4/64	6	8	13	410
		13	21	730
		14	23	1050
		17	27	1330
32/64	7	38	61	40
		52	84	80
		70	113	140
		87	140	200
		102	164	270
22/64	7	52	84	180
		62	100	250

Table A-9 - Experimental Pressure Drop Data

For The Cameron Manual Choke

Choke Position	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
22/64	7	74	119	340
		82	132	410
		94	151	520
16/64	7	39	63	200
		59	95	420
		77	124	690
		82	132	770
		88	142	870
13/64	7	33	53	280
		44	71	440
		55	89	670
		61	98	800
		74	119	1160
10/64	7	29	47	650
		37	60	910
		44	71	1110
		52	84	1450
		61	98	1700
8/64	7	20	32	560
		26	42	830
		32	51	1160
		37	60	1550

Table A-10 - Experimental Pressure Drop Data For The Cameron High Pressure Remote Choke

Choke Position inches	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
0.997	1	46	74	0
		78	126	40
		105	169	100
		117	188	120
0.667	1	35	56	20
		55	89	140
		74	119	250
		90	145	390
		103	166	500
0.550	1	37	60	130
		52	84	300
		63	101	420
		77	124	650
		89	143	830
0.428	1	34	55	230
		47	76	470
		54	87	580
		63	101	760
		69	111	880
0.380	1	21	34	250
		36	58	600
		43	69	840

Table A-11 - Experimental Pressure Drop Data For The Cameron High Pressure Remote Choke

Choke Position inches	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
0.380	1	52	84	1300
		58	93	1670
0.321	1	10	16	230
		16	26	490
		21	34	760
		24	39	1000
		26	42	1090
0.999	2	35	56	0
		56	90	50
		75	121	80
		87	140	100
		113	182	170
0.664	2	36	58	80
		48	77	140
		61	98	210
		69	111	280
		87	140	430
0.552	3	38	61	180
		58	93	380
		64	103	440
		77	124	590
		92	148	830

Table A-12 - Experimental Pressure Drop Data For The Cameron High Pressure Remote Choke

Choke Position inches	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
0.427	3	29	47	200
		39	63	380
		51	82	580
		62	100	820
		74	119	1200
0.379	3	25	40	360
		35	56	660
		41	66	900
		47	76	1170
		53	85	1500
0.322	3	15	24	500
		20	32	720
		23	37	1000
		26	42	1330
		31	50	1740
0.998	4	52	84	50
		64	103	70
		77	124	100
		87	140	110
		105	169	160
0.666	4	46	74	140
		59	95	230

Table A-13 - Experimental Pressure Drop Data For The Cameron High Pressure Remote Choke

Choke Position inches	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
0.666	4	70	113	350
		80	129	440
		88	142	520
0.552	4	29	47	200
		40	64	340
		51	82	500
		64	103	710
		77	124	1000
0.425	4	12	68	1300
		20	50	720
		26	42	500
		31	32	330
		42	19	200
0.319	4	8	13	400
		11	18	700
		16	26	1290
0.997	5	37	60	20
		63	101	70
		75	121	100
		88	142	130
		105	169	200

Table A-14 - Experimental Pressure Drop Data For The Cameron High Pressure Remote Choke

Choke Position inches	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
0.667	5	36	58	100
		47	76	160
		58	93	260
		70	113	360
		87	140	540
0.551	5	13	21	90
		27	43	210
		42	68	450
		59	95	700
		72	116	940
0.425	5	8	13	330
		13	21	600
		17	27	800
		21	34	1160
0.996	6	46	74	50
		60	97	70
		70	113	110
		87	140	160
		111	179	250
0.665	6	32	51	100
		48	77	210
		66	106	400

Table A-15 - Experimental Pressure Drop Data For The Cameron High Pressure Remote Choke

Choke Position inches	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
0.665	6	77	124	520
		92	148	750
0.551	6	26	42	240
		36	58	410
		49	79	660
		58	93	860
		74	119	1200
0.426	6	7	11	610
		10	16	800
		11	18	1000
		13	21	1170
		14	23	1380
0.997	7	62	100	80
		68	109	100
		81	130	140
		93	150	180
		100	161	200
0.665	7	39	63	210
		60	97	480
		70	113	590
		77	124	710
		87	140	860

Table A-16 - Experimental Pressure Drop Data For The Cameron High Pressure Remote Choke

Choke Position inches	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
0.552	7	20	32	160
		29	47	350
		40	64	630
		48	77	820
		59	95	1200
0.428	7	7	11	220
		12	19	680
		16	26	1200
		18	29	1570

Table A-17 - Experimental Pressure Drop Data

For The Swaco Super Choke

Choke Position	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
73°	1	34	55	20
		63	101	80
		81	130	150
		115	185	320
60°	1	42	68	80
		62	100	190
		77	124	300
		94	151	470
53°	1	29	47	60
		46	74	180
		60	97	320
		82	132	600
		93	150	800
40°	1	36	58	140
		46	74	260
		57	92	410
		72	116	690
		79	127	870
37°	1	24	39	100
		40	64	360
		59	95	720
		72	116	1100
		76	122	1220

Table A-18 - Experimental Pressure Drop Data

For The Swaco Super Choke

Choke Position	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
33°	1	34	55	400
		39	63	520
		46	74	750
		58	93	1200
		64	103	1480
30°	1	18	30	250
		30	48	570
		36	58	820
		44	71	1200
		51	82	1750
28°	1	19	31	390
		25	40	620
		33	53	1050
		38	61	1460
		42	68	1800
73°	2	39	63	70
		62	100	120
		69	111	160
		83	134	210
		90	145	260
60°	2	27	43	50
		42	68	100

Table A-19 - Experimental Pressure Drop Data

For The Swaco Super Choke

Choke Position	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
60°	2	62	100	210
		73	117	300
		93	150	480
53°	2	29	47	110
		47	76	250
		58	93	370
		70	113	500
		83	134	720
42°	3	36	58	180
		47	76	300
		56	90	430
		71	114	620
		86	138	940
37°	3	43	69	430
		53	85	620
		60	97	800
		66	106	970
		77	124	1300
33°	3	33	53	450
		39	63	630
		49	79	990
		58	93	1340

Table A-20 - Experimental Pressure Drop Data

For The Swaco Super Choke

Choke Position	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
33°	3	63	101	1600
30°	3	30	48	620
		35	56	800
		38	61	1010
		44	71	1320
		50	80	1670
73°	4	38	61	50
		61	98	130
		77	124	200
		94	151	280
		102	164	320
60°	4	32	51	70
		58	93	230
		70	113	300
		81	130	400
		93	150	500
53°	4	33	53	120
		40	64	200
		48	77	270
		66	106	500
		87	140	800
40°	4	28	45	130
		45	72	310

Table A-21 - Experimental Pressure Drop Data

For The Swaco Super Choke

Choke Position	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
40°	4	57	92	520
		76	122	900
		90	145	1200
37°	4	21	34	120
		34	55	350
		48	77	600
		57	92	880
		70	113	1250
33°	4	18	29	210
		23	37	390
		31	50	640
		42	68	1200
		47	76	1500
30°	4	12	19	340
		18	29	650
		26	42	1500
73°	5	39	63	50
		46	74	70
		53	85	100
		77	124	200
		98	158	320
60°	5	32	51	60
		61	98	230

Table A-22 - Experimental Pressure Drop Data

For The Swaco Super Choke

Choke Position	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
60°	5	72	116	320
		82	132	420
		100	161	580
53°	5	28	45	90
		45	72	240
		58	93	390
		74	119	610
		90	145	870
42°	5	36	58	230
		51	82	500
		62	100	700
		77	124	1040
		87	140	1290
37°	5	26	42	220
		37	60	420
		48	77	690
		64	103	1170
		72	116	1420
33°	5	15	24	190
		23	37	460
		32	51	800
		37	60	1080

Table A-23 - Experimental Pressure Drop Data

For The Swaco Super Choke

Choke Position	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
33°	5	45	72	1600
30°	5	7	11	390
		11	18	480
		16	26	870
		20	32	1100
73°	6	39	63	60
		55	89	100
		69	111	170
		83	134	240
		98	158	330
60°	6	32	51	70
		46	74	150
		62	100	270
		77	124	420
		90	145	570
53°	6	33	53	150
		45	72	240
		60	97	420
		72	116	580
		82	132	740
42°	6	46	74	400
		53	85	520

Table A-24 - Experimental Pressure Drop Data

For The Swaco Super Choke

Choke Position	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
42°	6	62	100	720
		74	119	1000
		82	132	1180
37°	6	23	37	180
		31	50	320
		44	71	630
		53	85	880
		64	103	1260
33°	6	18	29	310
		24	39	500
		27	43	630
		33	53	900
		40	64	1290
30°	6	8	13	200
		15	24	680
		20	32	1100
		22	35	1300
73°	7	32	51	50
		44	71	90
		62	100	160
		79	127	260
		99	159	380

Table A-25 - Experimental Pressure Drop Data

For The Swaco Super Choke

Choke Position	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
60°	7	40	64	110
		48	77	160
		66	106	290
		77	124	390
		94	151	570
52°	7	32	51	130
		48	77	280
		64	103	470
		72	116	580
		82	132	750
40°	7	27	43	200
		44	71	480
		52	84	690
		62	100	900
		68	109	1050
37°	7	21	34	280
		26	42	410
		35	56	750
		41	66	990
		47	76	1300
33°	7	10	16	210
		14	23	420
		20	32	780

Table A-26 - Experimental Pressure Drop Data

For The Swaco Super Choke

Choke Position	Drilling Fluid	Pump Rate spm	Flow Rate gpm	Pressure Drop psi
33°	7	24	39	1120
		27	43	1370
30°	7	6	10	540
		8	13	860
		10	16	1140
		11	18	1400

Table B-1 - Computation Of Valve Coefficients

For The Cameron Manual Choke

Choke Position	Drilling Fluid	Flow Rate gpm	Pressure Drop, psi	Valve Coefficient
0.500	1	175	260	10.85
		150	180	11.18
		125	110	11.92
		100	60	12.91
		75	20	16.77
0.344	1	175	490	7.91*
		150	370	7.80
		125	250	7.91
		100	150	8.16
		75	70	8.96
		50	20	11.18*
0.250	1	150	850	5.14*
		125	560	5.28
		100	340	5.42
		75	200	5.30
		50	90	5.27*
		25	20	5.59*
0.203	1	125	980	3.99
		100	630	3.98
		75	360	3.95
		50	170	3.83
		25	50	3.54*

*extrapolated value

Table B-2 - Computation Of Valve Coefficients

For The Cameron Manual Choke

Choke Position	Drilling Fluid	Flow Rate gpm	Pressure Drop, psi	Valve Coefficient
0.156	1	100	1230	2.85
		75	720	2.80
		50	350	2.67
		25	130	2.19*
0.125	1	75	1030	2.34
		50	490	2.26
		25	180	1.86
0.063	1	50	900	1.67
		25	330	1.38*
0.500	2	175	290	10.44*
		150	200	10.78
		125	130	11.14
		100	80	11.36
		75	40	12.05
0.344	2	175	510	7.87*
		150	380	7.82
		125	270	7.73
		100	170	7.79
		75	100	7.62
		50	50	8.03*
0.250	2	150	840	5.26

*extrapolated value

Table B-3 - Computation Of Valve Coefficients

For The Cameron Manual Choke

Choke Position	Drilling Fluid	Flow Rate gpm	Pressure Drop, psi	Valve Coefficient
0.250	2	125	610	5.14
		100	390	5.15
		75	220	5.14
		50	80	5.68
		25	20	5.68*
p.203	3	125	1000	4.02
		100	660	3.96
		75	380	3.91
		50	170	3.90
		25	40	4.02*
0.156	3	100	1250	2.87
		75	720	2.84
		50	340	2.80
		25	80	2.84*
0.125	3	100	1730	2.44
		75	1050	2.35
		50	500	2.27
		25	190	1.84*
0.0625	3	50	960	1.64
		25	360	1.34*
0.500	4	175	290	10.44*

*extrapolated value

Table B-4 - Computation Of Valve Coefficients

For The Cameron Manual Choke

Choke Position	Drilling Fluid	Flow Rate gpm	Pressure Drop, psi	Valve Coefficient
0.500	4	150	210	10.52
		125	140	10.73
		100	90	10.71
		75	50	10.78*
0.344	4	175	520	7.80
		150	390	7.72
		125	280	7.59
		100	180	7.57
		75	100	7.62*
0.250	4	150	850	5.23
		125	620	5.10
		100	400	5.08
		75	230	5.02
		50	90	5.36*
0.203	4	125	1040	3.94
		100	670	3.93
		75	400	3.81
		50	180	3.79*
		25	50	3.59*
0.156	4	100	1350	2.77
		75	770	2.75
		50	370	2.64

*extrapolated value

Table B-5 - Computation Of Valve Coefficients

For The Cameron Manual Choke

Choke Position	Drilling Fluid	Flow Rate gpm	Pressure Drop, psi	Valve Coefficient
0.156	4	25	110	2.42*
0.125	4	50	710	1.91
		25	220	1.71
0.0625	4	25	640	1.00
0.500	5	150	210	10.52*
		125	140	10.73
		100	90	10.71
		75	50	10.78
0.244	5	150	390	7.72*
		125	280	7.59
		100	180	7.57
		75	100	7.62
		50	50	7.18*
0.250	5	125	620	5.10
		100	400	5.08
		75	230	5.02
		50	100	5.08
		25	30	4.64*
0.203	5	100	700	3.84
		75	410	3.76
		50	200	3.59
		25	50	3.59*

*extrapolated value

B-6 - Computation Of Valve Coefficients

For The Cameron Manual Choke

Choke Position	Drilling Fluid	Flow Rate gpm	Pressure Drop, psi	Valve Coefficient
0.156	5	75	830	7.65
		50	420	2.48
		25	160	2.01*
0.125	5	50	830	1.76
		25	280	1.52
0.00625	5	25	920	0.84
0.500	6	175	280	11.85*
		150	210	11.73
		125	150	11.57
		100	100	11.33*
		75	60	10.97*
0.344	6	175	520	8.70*
		150	390	8.61
		125	280	8.47
		100	180	8.45
		75	100	8.50
0.250	6	150	860	5.80*
		125	620	5.69
		100	420	5.53
		75	240	5.49
		50	120	5.17*

*extrapolated value

Table B-7 - Computation Of Valve Coefficients

For The Cameron Manual Choke

Choke Position	Drilling Fluid	Flow Rate gpm	Pressure Drop, psi	Valve Coefficient
0.203	6	125	1100	4.27
		100	710	4.25
		75	450	4.01
		50	200	4.01*
		25	60	3.66*
0.156	6	75	1030	2.65
		50	520	2.49
		25	200	2.00*
0.125	6	50	1020	1.77
		25	320	1.58
0.0625	6	25	1180	0.82
0.500	7	175	300	12.15*
		150	230	11.90
		125	170	11.53
		100	110	11.47
		75	70	10.78
		50	30	10.98*
0.344	7	150	510	7.99
		125	370	7.82
		100	250	7.61
		75	140	7.62*
		50	60	7.76*

*extrapolated value

Table B-8 - Computation Of Valve Coefficients

For The Cameron Manual Choke

Choke Position	Drilling Fluid	Flow Rate gpm	Pressure Drop, psi	Valve Coefficient
0.250	7	150	970	5.79*
		125	690	5.72
		100	460	5.61
		75	270	5.49
		50	120	5.49*
		25	30	5.49*
0.203	7	125	1290	4.19*
		100	830	4.17
		75	500	4.03
		50	260	3.73*
		25	90	3.17*
0.156	7	100	1760	2.87*
		75	1200	2.60
		50	720	2.24
		25	320	1.68*
0.125	7	50	1150	1.77
		25	430	1.45*

*extrapolated value

Table B-9 - Computation Of Valve Coefficients For The Cameron High Pressure Remote Choke

Choke Position (inches)	Drilling Fluid	Flow Rate	Pressure Drop psi	Valve Coefficient
0.997	1	175	100	17.50
		150	70	17.93
		125	40	19.76
		100	20	22.36
		75	10	23.72
0.667	1	175	560	7.40*
		150	420	7.32
		125	280	7.47
		100	170	7.67
		75	70	8.96
0.550	1	150	930	4.92*
		125	660	4.87
		100	420	4.88
		75	230	4.95
		50	90	5.27*
		25	20	5.59*
0.428	1	125	1100	3.77*
		100	750	3.65
		75	450	3.54
		50	220	3.37*
		25	50	3.54*

*extrapolated value

Table B-10 - Computation Of Valve Coefficients For The Cameron High Pressure Remote Choke

Choke Position (inches)	Drilling Fluid	Flow Rate	Pressure Drop psi	Valve Coefficient
0.380	1	75	1030	2.34
		50	470	2.31
		25	150	2.04*
0.321	1	25	480	1.14
0.999	2	175	160	14.06
		150	120	13.91
		125	80	14.20
		100	50	14.37
		75	30	13.91
0.664	2	150	480	6.96*
		125	350	6.79
		100	220	6.85
		75	130	6.68
		50	40	8.03*
0.552	3	150	850	5.23*
		125	620	5.10
		100	420	4.96
		75	240	4.92
		50	120	4.64*
		25	30	4.64*

*extrapolated value

Table B-11 - Computation Of Valve Coefficients For The Cameron High Pressure Remote Choke

Choke Position (inches)	Drilling Fluid	Flow Rate	Pressure Drop psi	Valve Coefficient
0.427	3	125	1300	3.52*
		100	820	3.55
		75	480	3.48
		50	230	3.35
		25	60	3.28*
0.379	3	75	1160	2.24
		50	510	2.25
		25	150	2.07*
0.322	3	50	1740	1.22
		25	500	1.14
0.998	4	175	170	13.64*
		150	130	13.37
		125	90	13.39
		100	60	13.11
		75	40	12.05*
0.666	4	150	570	6.38*
		125	410	6.27
		100	260	6.30
		75	150	6.22
		50	50	7.18*

*extrapolated value

Table B-12 - Computation Of Valve Coefficients For The Cameron High Pressure Remote Choke

Choke Position (inches)	Drilling Fluid	Flow Rate	Pressure Drop psi	Valve Coefficient
0.552	4	125	980	4.06
		100	680	3.90
		75	430	3.67
		50	210	3.51
		25	80	2.84*
0.425	4	75	1600	1.91*
		50	720	1.89
		25	240	1.64
0.319	4	25	1180	0.74
0.997	5	175	200	12.57*
		150	150	12.44
		125	110	12.11
		100	70	12.14
		75	40	12.05
0.667	5	150	610	6.17*
		125	430	6.12
		100	280	6.07
		75	160	6.02
		50	70	6.07*
0.551	5	125	1040	3.94*

*extrapolated value

Table B-13 - Computation Of Valve Coefficients For The Cameron High Pressure Remote Choke

Choke Position (inches)	Drilling Fluid	Flow Rate	Pressure Drop psi	Valve Coefficient
0.551	5	100	760	3.69
		75	510	3.37
		50	260	3.15
		25	110	2.42
0.425	5	25	750	0.93
0.996	6	175	240	12.80
		150	180	12.67
		125	130	12.43
		100	80	12.67
		75	50	12.02
0.665	6	150	760	6.17*
		125	530	6.15
		100	350	6.06
		75	200	6.01
		50	80	6.34*
0.551	6	125	1280	3.96*
		100	930	3.72
		75	620	3.41
		50	330	3.12
		25	120	2.59*
0.426	6	25	1470	0.74*

*extrapolated value

Table B-14 - Computation Of Valve Coefficients For The Cameron High Pressure Remote Choke

Choke Position (inches)	Drilling Fluid	Flow Rate	Pressure Drop psi	Valve Coefficient
0.997	7	175	250	13.31*
		150	180	13.45
		125	130	13.19
		100	80	13.45
		75	40	14.26*
0.665	7	150	950	5.85*
		125	700	5.68
		100	490	5.43
		75	300	5.21
		50	130	5.27*
0.552	7	100	1310	3.32*
		75	810	3.17
		25	100	3.01*
0.428	7	25	1130	0.89

*extrapolated value

Table B-15 - Computation Of Valve Coefficients

For The Swaco Super Choke

Choke Position	Drilling Fluid	Flow Rate	Pressure Drop, psi	Valve Coefficient
73°	1	175	290	10.28
		150	220	10.11
		125	150	10.21
		100	80	11.18
		75	40	11.86
		50	20	11.18*
60°	1	175	620	7.03*
		150	470	6.92
		125	320	6.99
		100	190	7.25
		75	100	7.50
		50	30	9.13*
53°	1	150	800	5.30
		125	560	5.28
		100	340	5.47
		75	180	5.59
		50	70	5.98
40°	1	125	870	4.24
		100	500	4.47
		75	270	4.56
		50	100	5.00*

*extrapolated value

Table B-16 - Computation Of Valve Coefficients
For The Swaco Super Choke

Choke Position	Drilling Fluid	Flow Rate	Pressure Drop, psi	Valve Coefficient
40°	1	25	20	5.59*
37°	1	125	1300	3.47*
		100	800	3.54
		75	450	3.54
		50	180	3.73
		25	40	3.95*
33°	1	100	1370	2.70
		75	750	2.74
		50	340	2.71*
		25	100	2.50*
30°	1	75	1370	2.03*
		50	600	2.04
		25	200	1.77*
28°	1	50	900	1.67
		25	300	1.44
73°	2	150	270	9.78*
		125	190	9.21
		100	120	9.28
		75	70	9.11
		50	30	9.28*
60°	2	150	480	6.96

*extrapolated value

Table B-17 - Computation Of Valve Coefficients

For The Swaco Super Choke

Choke Position	Drilling Fluid	Flow. Rate	Pressure Drop, psi	Valve Coefficient
60°	2	125	340	6.89
		100	210	7.01
		75	120	6.96
		50	50	7.18
53°	2	150	860	5.20*
		125	620	5.10
		100	420	4.96
		75	250	4.82
		50	110	4.84
42°	3	150	1080	4.64*
		125	780	4.55
		100	510	4.50
		75	290	4.47
		50	130	4.46*
37°	3	125	1300	3.52
		100	850	3.49
		75	500	3.41
		50	220	3.43*
		25	50	3.59*
33°	3	100	1580	2.56
		75	860	2.60

*extrapolated value

Table B-18 - Computation Of Valve Coefficients

For The Swaco Super Choke

Choke Position	Drilling Fluid	Flow Rate	Pressure Drop, psi	Valve Coefficient
33°	3	50	400	2.54*
		25	100	2.54*
30°	3	75	1440	2.01
		50	650	1.99
		25	200	1.80*
28°	3	50	1170	1.49
		25	300	1.47*
73°	4	175	370	9.24*
		150	280	9.11
		125	200	8.98
		100	130	8.91
		75	70	9.11
		50	30	9.28*
60°	4	150	500	6.82
		125	350	6.79
		100	220	6.85
		75	130	6.68
		50	60	6.56
53°	4	150	890	5.11*
		125	650	4.98
		100	430	4.90

*extrapolated value

Table B-19 - Computation Of Valve Coefficients

For The Swaco Super Choke

Choke Position	Drilling Fluid	Flow Rate	Pressure Drop, psi	Valve Coefficient
53°	4	75	260	4.73
		50	120	4.64*
40°	4	150	1280	4.26*
		125	860	4.33
		100	560	4.29
		75	310	4.33
		50	160	4.02
37°	4	125	1500	3.28*
		100	1000	3.21
		75	580	3.16
		50	270	3.09
		25	70	3.04*
33°	4	75	1450	2.00
		50	640	2.01
		25	170	1.95*
30°	4	25	480	1.16
73°	5	175	380	9.12*
		150	290	8.95
		125	210	8.76
		100	130	8.91
		75	70	9.11

*extrapolated value

Table B-20 - Computation Of Valve Coefficients

For The Swaco Super Choke

Choke Position	Drilling Fluid	Flow Rate	Pressure Drop, psi	Valve Coefficient
73°	5	50	30	9.28*
60°	5	150	520	6.68
		125	350	6.79
		100	220	6.85
		75	130	6.68
		50	60	6.56
53°	5	150	910	5.05*
		125	670	4.91
		100	440	4.84
		75	260	4.73
		50	120	4.64
42°	5	150	1300	4.23*
		125	900	4.23
		100	590	4.18
		75	330	4.19
		50	160	4.02*
37°	5	125	1660	3.12*
		100	1100	3.06
		75	660	2.97
		50	290	2.98
		25	80	2.84*

*extrapolated value

Table B-21 - Computation Of Valve Coefficients For The Swaco Super Choke

Choke Position	Drilling Fluid	Flow Rate	Pressure Drop, psi	Valve Coefficients
33°	5	75	1730	1.83
		50	790	1.81
		25	200	1.80
30°	5	25	700	0.96
73°	6	175	400	9.92*
		150	300	9.82
		125	220	9.55
		100	130	9.94
		75	70	10.16
		50	30	10.35*
60°	6	150	600	6.94*
		125	420	6.91
		100	270	6.90
		75	160	6.72
		50	70	6.77*
53°	6	150	930	5.57*
		125	680	5.43
		100	450	5.34
		75	260	5.27
		50	120	5.17*
42°	6	125	1070	4.33

*extrapolated value

Table B-22 - Computation Of Valve Coefficients

For The Swaco Super Choke

Choke Position	Drilling Fluid	Flow Rate	Pressure Drop, psi	Valve Coefficients
42°	6	100	720	4.22
		75	410	4.20
		50	190	4.11*
		25	50	4.01*
37°	6	100	1180	3.30
		75	690	3.24
		50	320	3.17
		25	90	2.99*
33°	6	50	830	1.97
		25	200	2.00
30°	6	25	730	1.05
73°	7	175	450	9.92*
		150	340	9.78
		125	250	9.51
		100	160	9.51
		75	100	9.02
		50	50	8.50*
60°	7	150	570	7.56
		125	420	7.34
		100	270	7.32
		75	160	7.13

*extrapolated value

VITA

Kerry Patrick Redmann, Jr. was born on February 16, 1954 in New Orleans, Louisiana. He attended Jesuit High School in New Orleans, and graduated from there in May of 1972. Having accepted a scholarship to attend Loyola University, Kerry received a Bachelor of Science in Physics in December of 1978. The following January, he entered the Graduate School at Louisiana State University to obtain the degree of Master of Science in Petroleum Engineering.

Kerry is married to the former Darcy Ann Prichard, a native of New Orleans, also. They have two children, Kerry, III and Heather Marie.